

**Public Comments on the Proposed Revisions to Section 4.2  
Chapter 2 (SCR) of the  
Control Cost Manual**

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## Chapter 2: Selective Catalytic Reduction (SCR)

Comments were received from 10 sources, including electric generation entities, industry trade associations and consultants, state and local environment departments, environmental groups. Table 1 lists the individuals that submitted comments on the proposed updates to Chapter 2, Selective Catalytic Reduction. All of the comments submitted by the commenters and EPA's responses to the comments are summarized in this document.

**Table 1. List of Commenters for SCR**

<b>Document Control Number</b>	<b>Commenter Name</b>	<b>Commenter Affiliation</b>
EPA-HQ-OAR-2015-0341-0019	Justin B. Green, Director	Division of Air Resources Management, Florida Department of Environmental Protection
EPA-HQ-OAR-2015-0341-0020	Ted Steichen, Senior Policy Advisor	American Petroleum Institute (API)
EPA-HQ-OAR-2015-0341-0022	Paul Noe, Vice President for Public Policy	American Forest & Paper Association, et al.
EPA-HQ-OAR-2015-0341-0023	Michael Schon, Vice President and Counsel, Government Affairs	Portland Cement Association (PCA)
EPA-HQ-OAR-2015-0341-0024	Quinlan J. Shea III, Vice President - Environment	Edison Electric Institute (EEI)
EPA-HQ-OAR-2015-0341-0025	Gloria D. Smith, Managing Attorney	Sierra Club and National Parks Conservation Association
EPA-HQ-OAR-2015-0341-0026	Makram B. Jaber and Andrew D. Knudsen, Counsel	Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2015-0341-0027	Sheraz Gill, Director of Strategies and Incentives	San Joaquin Valley Unified Air Pollution Control District
EPA-HQ-OAR-2015-0341-0028	Charles Spell, Director of Environmental Policy and Programs,	Arizona Public Service Company (APS)
EPA-HQ-OAR-2015-0341-0029	Jeffrey I. West, Senior Director of Environmental Services	Xcel Energy Inc.

## 2.1 Introduction

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment: Disconnect between design discussion and Cost methodology.**

Both Chapters Should Be Renamed and the Content Clarified to make it Clear They Only Apply to SCR and SNCR Installations on Boilers  $\geq 25$  MW.

The first part of each draft Chapter<sup>1</sup> includes a process description and a discussion of considerations for estimating key parameters for sizing such systems and for estimating the major operating costs for such systems, based on retrofitting these controls on utility boilers firing coal. The cost estimating sections<sup>2</sup> then address the capital and operating costs associated with such installations on utility and industrial boilers.

The cost estimating sections only deal with boilers of  $\geq 25$  MW and unlike the existing Control Cost Manual Chapters that are being updated do not use any of the introductory material, process descriptions or design parameter discussions from the first part of each Chapter. Rather, the cost estimating equations for utility boilers are taken from a separate EPA evaluation of the electric utility industry, and the cost estimating equations for industrial boilers are derived from the utility boiler equations assuming costs are the same for utility boilers and industrial boilers with equivalent heat inputs. The derivation of the cost estimating procedures for utility boilers is not explained in the draft Chapters, but is available, in limited detail, on EPA's electric utility website.

The procedures in these Chapters are used in making *critical regulatory decisions*, since EPA requires or encourages use of the Control Cost Manual when making certain regulatory decisions, such as whether SCR represents Best Available Retrofit Technology (BART) for a particular combustion source<sup>3</sup>. Thus, it is critical that the applicability of these Chapters be clearly identified. Since the draft Chapter titles and the introductory material<sup>4</sup> do not suggest any limits to the applicability of the Chapters, API recommends that the Chapter titles be changed to reflect the fact that these Chapters only address cost estimating for boilers  $\geq 25$  MW. Furthermore, if our recommendations below that these Chapters not address industrial boilers are adopted, the Chapter Headings and introductory material should reflect that limitation on their applicability, as well.

The introductory material, process descriptions and design parameter discussions in the draft Chapters are ambiguous regarding equipment applicability and could be interpreted to apply to any SNCR or SCR system on any type of equipment, even though the information is only based on installation of such facilities on utility boilers and the Chapters only apply the information to boilers. Broad applicability of the introductory material, process descriptions and design parameter discussions is suggested, for instance, by the discussion in draft Chapter 2 Section 2.2.3 about application of SCR to gas turbine exhaust. While API agrees that these general

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<sup>1</sup> Sections 1.2 and 1.3 of Chapter 1 and Sections 2.2 and 2.3 of Chapter 2.

<sup>2</sup> Sections 1.4 and 1.5 of Chapter 1 and Sections 2.4 and 2.5 of Chapter 2.

<sup>3</sup> See, for instance, *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations* at 70 FR 39166 (July 6, 2005), where it states relative to BART determinations "In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible."

<sup>4</sup> Section 1.1 of Chapter 1 and Section 2.1 of Chapter 2.

discussions might allow for rough estimates of catalyst bed sizes and reagent needs for installations on non-boiler types of equipment, the information does not indicate how to adjust for differences in equipment design or exhaust gas properties between equipment types or the significant differences in SCR system construction approaches needed to deal with those differences. For instance:

- SCR effectiveness depends on obtaining the needed catalyst temperature and residence time. Therefore, for instance, retrofits of SCR onto process heaters can often require very expensive convection section revisions as well as loss of significant heater duty.
- SCR sizing, location, catalyst type, etc., will also vary between equipment types and even from unit to unit of the same type due to the differences in their designs, temperature profiles, heat densities, etc.
- Similarly, application of SCR technology to Fluid Catalytic Coker Units (FCCUs) involves many unique construction and operational issues, including having to locate the SCR system high in the air, dealing with CO combustion in addition to fuel gas combustion and dealing with extreme temperature and NO<sub>x</sub> variations as operating conditions change.
- For process heaters and FCCUs, the SCR system often must be constructed in a vertical configuration above grade. The foundation and structural costs for vertical configurations drastically increase construction costs. In some cases, expensive soil studies are required to provide the information required for foundation design. Members report that dealing with these issues can result in costs for installing SCR on these equipment types that are much higher than the costs for installing SCR on boilers.
- Costs can also be significantly impacted by the level and form of the NO<sub>x</sub> limitation and how that limit is applied during periods of startup and shutdown, since additional facilities (e.g., catalyst and reagent volume) may be needed to achieve a particularly low emission limit or to address variability.

API applauds the places in these introductory discussions where the differences between utility boilers and other equipment types are mentioned, but we request that these be strengthened and it be made clearer that project specific estimates, not use of the Control Cost Manual equations, are necessary for determining the cost of applying SCR and SNCR to non-boiler installations and to installations on boilers of <25 MW capacity. Furthermore, to reduce confusion, API recommends that the discussion of gas turbine installations in Section 2.2.3 of draft Chapter 2 be deleted.

**Response:** While we agree there are some differences between utility and industrial boilers, we believe these differences are minor and that the IPM is a reasonable and appropriate approach to estimating study-level costs for industrial boilers. As we note in the SCR chapter, study-level estimates by construction incorporate approximations that result in cost estimates that have an accuracy of  $\pm 30$  percent. Where more accurate cost estimates are needed, we recommend capital and operating costs be determined based on detailed design specifications and extensive quotes from suppliers.

We also disagree that the SCR chapter should be renamed or otherwise revised to indicate the chapter applies only to boilers greater than 25 MW. The SCR chapter includes general information regarding the design and operation of SCRs that is of general applicability to SCRs

applied to any type and size of combustion and process unit. We included information for other types of units such as gas turbines, FCCUs and process heaters because SCRs are used to control NOx emissions from these units. For example, the petroleum refinery industry reports SCR use for 151 process units at 35 facilities. In addition, the refinery industry reports SCR use on 13 FCCUs at 13 facilities.

While we agree the cost methodology is more applicable to larger units, we note that Chapter 2 clearly indicates the cost estimation approach is applicable only to units greater than 25 MW or greater than an equivalent heat input of roughly 250 MMBtu/hr. Unfortunately, the EPA does not have sufficient information available on the capital and operating costs for boilers below these cutoffs or for other types of units, such as FCCUs, process heaters, or cement kilns. We also note that parts of the cost methodology can still be used to estimate costs for smaller units. For example, reagent costs can be reliably estimated for other types and sizes of unit using the methodology presented in the Cost Manual.

#### ***Comments on Tables 2.1a and 2.1b***

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** Table 2.1b Should Be Deleted.

Tables 2.1a and b provide tabulations of cost data for installation of SCR from published and EPA sources for a variety of combustion unit types. Table 2.1a appears to represent actual cost data for utility coal-fired boiler SCR installations. However, Table 2.1b, which tabulates cost data for a variety of non-utility combustion sources, appears to contain primarily estimates, rather than actual cost data, and thus presents a false story, because:

- The number of actual cost data points are limited. Only 14 of the 34 entries seem to represent actual experience. Most of the entries (20 of 34) are based on vendor quotes and estimates of installation costs using Control Cost Manual factors or are scaled estimates from a single data point. Thus, this information does not represent actual cost data for boilers, as the Table seems to purport.
- Data included for non-boiler source types (i.e., process heaters, gas turbines, FCCUs, Cement Plants and IC Engines) in the Table have no bearing on boiler SCR installation costs, which is all this draft Chapter actually addresses. Their inclusion in the Table suggests this Chapter has broader application than it actually does and thus including that information is inappropriate.

**Response:** Tables 2.1a and 2.1b were intended to provide example capital costs for past SCR projects and to show the range and types of units that have installed SCR over time. The EPA agrees with the commenter that “estimated” costs were included alongside “actual” cost data in Table 2.1b, and has added a column to the table indicating whether the data reflects “actual” costs, “estimated” costs, or “vendor quotes”, as could best be determined with the available information for each unit.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The information about capital costs for cement plant SCR applications in Table 2.1.b grossly understates the estimated costs of SCR application at cement kilns. The data in Table 2.1.b consist of “cost estimates” for SCR systems that were never built, and the data are relatively few and outdated. With the exception of one data point from 2011, the cost figures were prepared during the 2004-2006 timeframe and are inconsistent with current SCR experience and design in Europe. In the 2004-2006 time period when the data were prepared, only one cement SCR in Europe had any operational history, and the full extent of capital and operating costs for that particular SCR application was unknown at the time. Consequently, those early cost estimates were not based on knowledge gained from cement plant experience; rather, the estimates were based on experience from other industries. The data point from 2011 comes from an estimate for an SCR that was never constructed and therefore does not represent the capital cost for an actual cement plant SCR installation. In short, the data are outdated and have little relevance to assessing the current cost of installing and/or operating SCR at U.S. cement kilns.

The capital cost estimates provided in Table 2.1.b range from \$4.4-\$6.9 per ton of clinker produced (\$/T<sub>c</sub>) for precalciner kiln systems and \$15.6-\$17.5/T<sub>c</sub> for wet kilns. Available initial cost information for the SCRs installed in Europe between 2010 and 2012 indicates the actual costs for precalciner kilns to be in the range of \$17-\$20/T<sub>c</sub>. It is not known if the reported costs include additional costs related to catalyst replacement and the cleaning system required during the initial period of operation. The costs to replace the initial catalyst for a catalyst that is more suitable to the actual gas conditions and dust loading, and the costs for required adjustments to the initial catalyst cleaning systems must be included in the estimate for it to be accurate and useful. Actual capital costs from the limited applications in Europe are 2.5-4.3 times the cost estimates found in the Table 2.1.b for precalciner kilns.<sup>5</sup>

The capital costs expected for SCR application at cement kilns in the U.S. makes SCR infeasible for most kilns. As stated above, capital costs are expected to be much greater than reflected in Table 2.1.b. Long-wet and dry kilns have lower production rates much higher operational costs (in dollars per ton of clinker produced) than preheater, precalciner kilns. As such, long-wet and dry kilns are unlikely to continue to be economical to operate if the high costs associated with SCR were required.

The commenter recommended the data in Table 2.1b for Portland cement kilns be deleted and the following be added to the discussion of Table 2.1a in section 2.1:

“Table 2.1a provides capital cost estimates for electric utility boilers, and Table 2.1b presents capital cost estimates for SCR applications of various sizes in several other industry source categories. Cost estimates for SCR for the cement industry have not been included as cost information for the only existing cement plant SCR in the US is not publicly available.”

**Response:** Table 2.1a was intended to provide example capital costs for past SCR projects and to show the range and types of units that have installed SCR over time. While some data may be

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<sup>5</sup> Information available for three cement SCR applications constructed in Europe between 2010 and 2012 indicates capital investments between 10.3M-16M euros (when converted to 2015 USA dollars the capital costs become \$15M-\$22M).

for older units, the cost year is clearly identified in the table for each entry and should be acceptable as example costs. We agree with the commenter that long-wet and dry cement kilns have lower production rates than the newer preheater/precalciner cement kilns; however, as with other control technologies, feasibility determinations and cost estimates must be made for each individual emissions source based on an evaluation of its site-specific characteristics. The EPA agrees with the commenter that “estimated” costs were being included alongside “actual” cost data in Table 2.1b, and has added a column indicating whether the data reflects “actual” costs, “estimated” costs, or vendor quotes, as could best be determined with the available information for each unit.

### ***Hybrid SNCR/SCR***

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** Chapter 2, Page 2-1

It is stated that “SCR can be applied as a stand-alone NO<sub>x</sub> control or with other technologies, including selective non-catalytic reduction (SNCR) and combustion controls such as low NO<sub>x</sub> burner (LNB) and flue gas recirculation (FGR) [2].” API suggests removing the SNCR example. If SCR catalyst is present, by definition, SNCR cannot be present.

**Response:** As of March 2016, the EPA knows of no operating hybrid SNCR/SCR air pollution control devices. However, the hybrid SNCR/SCR control was demonstrated at the AES Greenidge Power Plant in New York, and an Austrian coal-fired power plant. The technology is also marketed by manufacturers. In the hybrid control, a SNCR is followed by a SCR, and provides reduced capital costs because a smaller SCR unit is used. At the AES Greenidge Power Plant, the NO<sub>x</sub> controls on the utility boiler were installed in 2006 and included over-fire air (OFA), natural gas reburn, SNCR, and SCR. Unit No. 4 was shut down in 2011; however, recently the facility applied for a Title V Operating Permit and a Title IV Permit for the unit to burn primarily NG with the option to burn untreated wood, waste wood product from a furniture manufacturer, No. 2 fuel oil, diesel oil, waste oil, and/or natural gas. The hybrid SNCR/SCR was included in the permit application as part of the control technology on the boiler unit. The Facility Permits were open for public comment through September 2015. (B.Cassell, *Greenidge Coal Plant In New York to be Revived – without Coal*. *GenerationHub*. August 14, 2015. Accessed October 2015. <http://generationhub.com/2015/08/14/greenidge-coal-plant-in-new-york-to-be-revived---w>).

We have retained the hybrid SNCR/SCR system in section 2 and have also included a footnote that a demonstration project was completed, however no hybrid SNCR/SCR systems are currently known to be operating. In general, hybrid SNCR/SCR systems allow a smaller SCR unit and use of less catalyst, and therefore a lower overall total capital investment than an SCR alone. The system approach includes overfeed of NH<sub>3</sub> in the SNCR, that is used in the SCR. For additional information, please see the 2015 article in the AWMA Journal “Hybrid selective noncatalytic reduction (SNCR)/selective catalytic reduction (SCR) for NO<sub>x</sub> removal using low-temperature SCR with Mn-V<sub>2</sub>O<sub>5</sub>/TiO<sub>2</sub> catalyst.”



### ***SCR Application to Other Types of Units***

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** This chapter focuses primarily on the application of SCR to utility boilers, although a small amount of information presented shows that a few industrial units have installed SCR. As with SNCR, there are a number of source types for which SCR is not practical or feasible. Due to the nature of the flue gas path, package boilers typically do not have a suitable location in the proper temperature range to successfully install an ammonia injection grid (AIG) and catalyst. SCR is not technically feasible on most types of kilns due to their high exhaust gas exit temperatures. It is also not applicable to units such as chemical recovery furnaces, biomass boilers, and boilers firing North Dakota Lignite that have high sodium, potassium, phosphorus, and/or calcium content in the fly ash because these elements blind the catalyst and render it inactive. Industrial boilers also experience more frequent and more dramatic load swings than utility boilers, causing the temperature at a given point in the flue gas path to undergo rapid changes, resulting in difficulty in properly locating an SCR to achieve a consistent reduction in emissions.

**Response:** We agree that SCR may not be feasible for all units due to site-specific characteristics of the design and operation of the unit. However, we disagree with the commenter's statements regarding the feasibility of SCR. SCRs have been installed on package boilers and used successfully to control NO<sub>x</sub> emissions from various industrial combustion units (see Table 2.1b). SCRs have also been employed on biomass-fueled boilers and incinerators. For example, the BMC Moerdijk plant in the Netherlands uses a tail-end SCR on a unit combusting poultry litter. Each combustion unit must be assessed on an individual basis to determine whether SCR is a feasible control technology based on its site-specific characteristics and the SCR technology available at the time.

**Commenter:** Portland Cement Association

**DCN:** EPA-HQ-OAR-2015-0341-0023-A1

**Comment:** PCA believes that the draft fails to adequately represent the fact that SCR application at cement kilns is not currently feasible and realistic cost estimates for their installation and operation are difficult to make. Cement plant SCR applications present significant challenges that are not experienced in other industrial facilities, especially utility and industrial boilers where most operating SCR systems have been installed. The cement industry faces site-specific challenges that impact design, operation, and the cost of both installing and operating SCR technology. This is, in part, due to the impact of site-specific facility design, site-specific raw material ingredients, and other issues. The Cost Manual fails to account for these issues.

The designs of currently operating kilns in the United States vary among long-wet, long-dry, preheater, and precalciner kiln systems. They also vary in terms of age, design, and production capacity. All of these elements affect SCR performance and control efficiency.

SCR performance at cement kilns is also impacted by raw-materials. Cement plants must be located where adequate supplies of limestone and other raw materials that contain the required silica, alumina and iron are present. Cement plants can have different raw material and stack gas chemistry from trace elements associated with the site-specific raw materials. This variability appears to be much greater among kilns operating in the U.S. than the kilns with SCR applications in Europe. Perhaps the most significant difference between most U.S. kilns and the European kilns with SCRs is the presence and variability of pyritic sulfur in the limestone and other mined raw materials resulting in variable kiln system SO<sub>2</sub> emissions. The presence of SO<sub>2</sub> in the kiln gas prohibits the utilization of low temperature SCR catalyst systems. Where sulfur/SO<sub>2</sub> is present, the SCR must be operated above the temperature range for ammonium bisulfate salt formation (ABS) or it will plug or poison the catalyst. Sulfur poisoning or ABS formation has not been an issue in European cement SCR applications because the limestone in applicable areas of Europe contains very low sulfur content or pyrite. Unlike many U.S. kilns, minimal SO<sub>2</sub> concentrations are found in the kiln gas at the SCR inlet at the European kilns.

Another critical factor presenting challenges for cement kiln SCR application is the high dust loading for the “high dust” SCR. For example, dust loading at a typical coal-fired utility boiler using Powder River Basin (PRB) coal is between 10-20 g/Nm<sup>3</sup>. The typical dust loading at a preheater kiln is 80-100 g/Nm<sup>3</sup> and for some precalciner kilns, the dust loading may be 180 g/Nm<sup>3</sup> or higher. The high dust loading necessitates extensive dust removal systems to prevent dust buildup on the top of the catalyst layers as well as the plugging of the catalyst. The dust contains lime, which is known to “poison” the catalyst, and cement dust, which in many cases is sticky and difficult to remove. As noted in Section 2.2.2, page 2-21, of the Cost Manual, soot blowers may be activated once per week and sonic horns may sound for 10 seconds of every 10 minutes to assist in removing dust in other industrial SCR applications. However, those measures are not sufficient in high dust SCR systems (where the SCR is placed before the particulate control device) or semi-dust systems (where the SCR is placed after partial removal of particulate from a hot gas stream). European cement plant SCR applications expended considerable effort to develop compressed air cleaning systems to perform continuous cleaning of the catalyst layers, but periodic manual cleaning is still required. This results in the shut down or bypassing of the SCR for cleaning and dust removal.

An additional challenge for cement plants is that while slip stream pilot tests provide valuable design information, they do not necessarily address or simulate full scale operations. As a result, the selection of catalyst pitch can be a trial-and-error analysis. Available information shows that all of the semi-dust and high-dust SCR applications in Europe experienced plugging and high pressure drop problems. The problems eventually resulted in changes of the original catalyst for larger pitch, or in modifications in the shape of the openings in the catalyst along with adjustments and improvements in the catalyst cleaning systems. All of the applications experienced significant SCR downtime for catalyst cleaning or replacement during the initial years of operation.

While there is adequate data available to predict catalyst life for utility and industrial boilers, the same is not true for SCR applications in the cement industry. The experience of European manufacturers has indicated that initial catalyst selections may not prove to be appropriate for high-dust and semi-dust systems and may require catalyst replacement after a year or less of operation. Further, trials of various catalyst pitch sizes and shapes may be necessary before determining an acceptable catalyst for long-term use. Due to the more complicated gas chemistry in the U.S., where pyritic sulfur in the raw material is higher and more variable over time, there are questions that must be addressed before this technology could be employed, such as:

- When adjusted for site-specific conditions, will the catalyst have a life expectancy of 3 years or more?
- How many times may the catalyst be reactivated before it must be replaced with new catalyst?
- Does the more frequent and aggressive cleaning or dust removal system required for cement applications result in accelerated deterioration of catalysts?

These factors show that the removal, reactivation, and/or replacement of the catalyst create significant capital and operational costs and operational challenges that cannot be adequately predicted for any specific kiln-system based upon the data that is currently available.

The commenter recommended the following be added to the end of the first paragraph in section 2.1:

“Due to the challenges created by very high dust loading and the chemistry of cement kiln exhaust gases, the transfer of SCR technology to the cement industry has proven to be challenging. There is only one cement plant application of SCR operating in the U.S. which began operation in 2013. It is a semi-dust system with limited applicability for other kilns. There are only a handful of SCR applications on cement plants in Europe. Therefore, information on capital and operating costs for SCR for cement plants is very limited. Site specific differences in the raw material chemistry, especially the presence of pyritic sulfur, which is present in the U.S. but has not been present in the European applications, results in even greater uncertainties for operational uptime, NO<sub>x</sub> control efficiency and costs.”

PCA also supported the following statement in the introduction to Chapter 2 (page 2-2): “The procedures to estimate capital costs are not directly applicable to sources other than utilities and industrial boilers.” PCA also recommended the following revisions to further support and expand the statement.

“It is important to note that SCR has not been established as a feasible technology for cement kilns in the United States. Currently, there is only one SCR operating on a U.S. cement kiln. Information regarding its costs and operations is not publically available. However, the SCR equipped kiln and its associated emissions control systems are unique and do not represent an application that could be transferred to other U.S. cement facilities. The SCR is installed on a long-dry kiln that is equipped with a hot electrostatic precipitator (ESP) which removes a significant portion of the particulate/dust from the kiln gases prior to the kiln gas entering the SCR. The use of a hot ESP, which is critical to that system’s design, allows the gas stream to remain within the necessary temperature range for SCR (570° to 840°F) and reduces the dust loading to the unit without additional equipment and costs to reheat the gas. Site-specific

concerns regarding the potential formation of dioxins and furans, and new particulate emissions standards may prevent other U.S. kilns from utilizing this type of SCR system.<sup>6</sup> As such, costs and performance information for the one SCR application at a cement kiln in the U.S., even if it were available, would have limited utility for purposes of the Cost Manual.”

The commenter further recommended the following be added to the end of the second paragraph in section 2.1:

“The only SCR on a cement kiln in the US was designed for a control efficiency of 80%. Those operating on European kilns were either designed for odor control, or were designed to achieve a specific outlet NO<sub>x</sub> emissions rate (200 mg/Nm<sup>3</sup> for waste burning kilns) rather than a specific control efficiency. Operating data in Europe demonstrates that they typically meet that emissions rate which represents a control efficiency of about 80% depending on the type of kiln.”

**Response:** We thank the commenter for their input on the potential difficulties of implementing SCRs in the cement industry. We have incorporated into the final chapter many of the concerns raised by the commenter in this and later comments regarding application of SCR to the cement industry. However, we were unable to corroborate all of the comments provided and consequently did not include in the final chapter all of the text recommended by the commenter.

In the text recommended in this comment, the commenter stated that the transfer of SCR technology to the cement industry “has proven to be challenging” and that “greater uncertainties for operational uptime” exist for the U.S. cement industry due to the chemical constituents in the raw materials used. However, the commenter did not cite any specific instances where SCR had proven to be challenging, resulted in excessive periods of kiln shutdown, caused premature catalyst failure, or resulted in other technical issues with SCRs installed on cement kilns. The commenter did not provide any analytical data supporting their statement that the raw materials used in U.S. plants are significantly different from those used in European cement plants. Since we are unable to substantiate these specific statements, it would be inappropriate to include the text exactly as recommended by the commenter. We agree that efficiency and operating costs of SCRs can be negatively impacted by both high-levels of dust and the presence of catalyst poisoning and fouling constituents in the flue gas. However, we note that tail-end SCRs and SNCR/SCR hybrid systems have been found effective for certain types of high-dust applications. Alkali poisoning of the catalyst can occur due to trace quantities of potassium and sodium present in the raw materials and fuels. Catalyst fouling caused by the deposition of sulfate and bisulfate salts can also present problems for efficient SCR operation. However, one study of cement plants in Ellis County, Texas concluded that deactivation by alkali poisoning and fouling was not expected to be a significant problem, stating that “Neither the alkali percentages, the sulfur percentages nor the stack concentrations . . . could be considered high for SCR utilization in coal-fired plants.”<sup>7</sup>

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<sup>6</sup> When combustion gases remain at temperatures between 450°F and 750°F for an adequate retention time, such as is experienced within a baghouse or electrostatic precipitator (ESP), and adequate precursors are present, dioxin/furan (D/F) emissions compounds may form. As a result, most US cement plants quench kiln gases to temperatures below 400°F prior to the inlet to the air pollution control device (APCD) to ensure compliance with D/F emissions limits. Emissions limitations for particulate emissions from kilns have and will be lowered to levels that are not achievable by an ESP. Further an ESP is not considered to be Best Available Control Technology (BACT) for new kilns.

<sup>7</sup> Texas Commission on Environmental Quality. *Assessment of NO<sub>x</sub> Emissions Reduction Strategies for Cement Kilns – Ellis County*. Final Report. Prepared by ERG. July 14,

Nevertheless, we agree with the commenter that the U.S. cement industry has little experience with SCR and that the limited information available is from a small number of SCR applications in Europe. As with other control technologies, each emission source must be evaluated to determine whether SCR is a feasible control technology based on its site-specific characteristics. We have added the following paragraph to Section 2.1 of the SCR chapter to address these concerns:

“In the cement industry, pilot tests in the 1970s and 1990s showed SCR was a feasible control technology for cement kilns. Building on that experience, SCRs were first installed in Europe in 2001. Today, SCR has been successfully implemented at seven European cement plants in Solnhofen, Germany (operated from 2001 until 2006), Bergamo, Italy (2006), Sarchi, Italy (2007), Mergelstetten, Germany (2010), Rohrdorf, Germany (2011), Mannersdorf, Austria (2012), and Rezzato, Italy (2015). [94, 98, 99]. As of 2015, only one cement plant in the U.S. had installed an SCR. This SCR began operation in 2013 and is installed after an electrostatic precipitator. The control efficiency for the system is reported to be about 80%, which is consistent with SCR applications on European kilns. SCRs have not seen widespread use in the U.S. cement industry mainly due to industry concerns regarding potential problems caused by high-dust levels and catalyst deactivation by high SO<sub>3</sub> concentrations from pyritic sulfur found in the raw materials used by U.S. cement plants. The SO<sub>3</sub> could react with calcium oxide in the flue gas to form calcium sulfate and with ammonia to form ammonium bisulfate. The calcium sulfate could deactivate the catalyst, while the ammonium bisulfate could cause catalyst plugging. There have been concerns expressed about the potential for catalyst poisoning by sodium, potassium, arsenic trioxide, and calcium sulfate. Finally, other concerns expressed are that dioxins and furans may form in the SCR due to combustion gases remaining at temperatures between 450°F and 750°F. These and other concerns regarding the implementation of SCR to the cement industry are discussed in detail in “Alternative Control Techniques Document Update – NO<sub>x</sub> Emissions from New Cement Kilns” [94]. Due to the small number of SCRs installed at cement plants, information on capital and operating costs for SCRs at cement plants is limited. The installation and operating costs of the SCR installed at the U.S. plant in 2013 is not publicly available at this time. In general, we expect the capital and operating costs would be higher than for low-dust applications due to the need to install catalyst cleaning equipment for SCR systems installed in high-dust configurations and for heating the flue gas in low-dust, tail-end configurations.”

The following references were added to the end of the SCR Chapter:

[94] U.S. Environmental Protection Agency, “Alternative Control Techniques Document Update – NO<sub>x</sub> Emissions Controls for New Cement Kilns,” EPA-453/R-07-006, November 2007.

[98] Kline, John, “Is SCR Technology Coming (Back) to Cement?”, presentation by John Kline Consulting, April 2013. (<http://www.slideshare.net/jporterklne/is-scr-technology-coming-back-to-cement>).

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2006. Available at [www.tceq.state.tx.us/implementation/air/sip/BSA\\_settle.html](http://www.tceq.state.tx.us/implementation/air/sip/BSA_settle.html).

[99] EKomeri, Offshore and Energy Information and Technologies, “Semi-Dust SCR at Mannersdorf,” October 21, 2015. Available at <http://www.ekomeri.com/semi-dust-scr-mannersdorf/>.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph in section 2.1 be revised as shown:

“The procedures for estimating costs presented in this report are based on cost data for SCR retrofits on existing coal-, oil-, and gas-fired boilers for electric generating units larger than 25 MWe (approximately 250 MMBtu/hr). Thus, this report’s procedure estimates costs for typical retrofits of such boilers. The methodology for utility boilers also has been extended to large industrial boilers by modifying the capital cost equations and power consumption (electricity cost) equations to use the heat input capacity of the boiler instead of electric generating capacity.<sup>2</sup> The procedures to estimate capital costs are not directly applicable to sources other than utility and industrial boilers and should not be utilized for other applications, particularly those for cement kilns where dust loading and gas chemistry present unique and costly challenges for design and operation. Duct configurations and locations may be particularly problematic when trying to install a control technology at the right operating conditions for effective emissions control. Procedures to estimate annual costing elements other than power consumption are the same for SCR units in any application. The cost for SCR as part of a new plant often is likely to be less than would be estimated using these procedures. In addition, the cost procedures in this report reflect individual SCR applications. Retrofitting multiple boilers with SCR can allow for some economies of scale for installation, thus yielding some reduction in capital costs per SCR application. The cost methodology incorporates certain approximations; consequently, it should be used to develop study-level accuracy ( $\pm 30\%$ ) cost estimates of SCR applications. Such accuracy in the cost methodology is consistent with the accuracy of the cost estimates for the other control measures found in this Cost Manual as stated in Section 1.”

**Response:** The EPA agrees with the commenter that the calculation methods were developed using cost data specific to utility boilers and that the methods may not be directly applicable to cement kilns. However, we have not included the statements recommended by the commenter in the final chapter. The existing text clearly states that the cost methods apply to utility and industrial boilers and indicates that the methods would not be directly transferrable to other types of units. The commenter provided no cost data to support the assertion that “dust loading and gas chemistry present unique and costly challenges for design and operation” of SCRs for cement kilns. We have not been able to locate data confirming these factors would make SCRs more costly and challenging and note that SCRs have been successfully used on cement plants in Europe, demonstrated in pilot plant tests, and are used on coal-fired boilers, where the flue gas also has high dust loading and contains high levels of SO<sub>3</sub> and other constituents.

## 2.2 Process Description

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to section 2.2:

“Capital and operating costs for SCRs installed in cement plant applications must address the higher dust loading, as much as 18 times that of a coal-fired utility boiler as well as a more difficult dust to handle with its trace element contamination with catalyst poisons (sodium, potassium, arsenic, phosphorus, lead, chromium, and zinc), and physical handling characteristics “sticky dust”. These factors result in higher capital costs for much more extensive catalyst cleaning systems, and higher operational costs associated with energy consumption for the compressed air utilized for catalyst cleaning, and additional fan capacity necessary to address the higher pressure loss across the catalyst.”

**Response:** We agree with the commenter that SCR systems applied to units with high dust loading and high concentrations of sulfur and other compounds may deactivate SCR catalysts and hence increase the capital and operating costs of an SCR. However, we note that the Control Cost Manual chapter already addresses the need for catalyst cleaning equipment for high dust applications and describes the potential problems related to catalyst plugging, fouling, and poisoning. We do not believe these issues are unique to cement plants. We note that tail-end SCRs have been successfully employed in high dust situations. We agree that catalyst fouling and alkali poisoning can occur due to trace quantities of sodium, potassium, and other components present in the raw materials and fuels. One report indicated that alkali compounds may be a problem for cement plants due to elevated levels of potassium and sodium, but concluded that arsenic was not expected to cause catalyst poisoning at cement plants because it would react with the CaO and hence would not be available to bond to the catalyst surface.<sup>8</sup> Another study of cement plants in Ellis County, Texas concluded that deactivation by alkali poisoning and fouling was not expected to be a significant problem, stating that “Neither the alkali percentages, the sulfur percentages nor the stack concentrations . . . could be considered high for SCR utilization in coal-fired plants.”<sup>9</sup> In response to other comments provided by this commenter, we have included discussions of these and other issues related to cement plants in the final chapter (see sections 2.1, 2.2.2, 2.2.4, 2.2.6, and 2.3).

However, while we agree the factors cited by the commenter would likely result in capital and operating costs that are higher than low-dust applications, we have no data showing these costs would be significantly higher for cement kilns than for other similar applications. Since the revised Control Cost Manual chapter already addresses the additional costs associated with these

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<sup>8</sup> Schreiber, Robert J., Christa O. Russel, and Jeff Evers, “Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry”, undated. Submitted by the Portland Cement Association to the Ozone Transport Commission in 2006. Available at <http://www.otcair.org/upload/Interest/StationaryArea%20Sources/PCA%20SCR%20assessment%20final.pdf>.

<sup>9</sup> Texas Commission on Environmental Quality. *Assessment of NO<sub>x</sub> Emissions Reduction Strategies for Cement Kilns – Ellis County*. Final Report. Prepared by ERG. July 14, 2006. Available at [www.tceq.state.tx.us/implementation/air/sip/BSA\\_settle.html](http://www.tceq.state.tx.us/implementation/air/sip/BSA_settle.html).

types of applications and the additional text recommended by the commenter does not add any new substantive information, we did not include this text in the final revised chapter.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph in section 2.2 be revised:

“There are several different locations downstream of the combustion unit where SCR systems can be installed. Flue gas temperature and constituents vary with the location of the SCR reactor chamber. SCR reactors located upstream of the particulate control device and the air heater (“high-dust” configuration) have higher temperatures and higher levels of particulate matter. An SCR reactor located downstream of the air heater, particulate control devices, and flue gas desulfurization (FGD) system (“low-dust” or “tail-end” configuration) is essentially dust- and sulfur-free but its temperature is generally below the acceptable range. In this case, reheating of the flue gas may be required, which significantly increases the SCR operational costs. Section 2.2.3 discusses the various SCR system configurations. Due to the high dust loading in cement applications, a third option has been utilized, referred to as semi-dust SCR. In this instance the gas stream passes through a hot electrostatic precipitator to remove the majority of the dust prior to entering the SCR. The gas may then pass through a second, more efficient particulate control device to remove the remaining particulate to acceptable emissions rates.”

**Response:** The EPA thanks the commenter for their input. We have added the following sentences to Section 2.2.3, where SCR system configurations and tail-end SCRs are discussed in more detail.

“In the SCR installed at a U.S. cement kiln in 2013, the gas stream passes through a hot electrostatic precipitator to remove the majority of the dust prior to entering the SCR. The gas stream existing the SCR may then pass through a second, more efficient particulate control device to remove the remaining particulate to acceptable emissions rates.”

## **2.2.1 Reduction Chemistry, Reagents, and Catalyst**

### **Introduction paragraph**

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

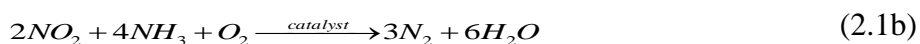
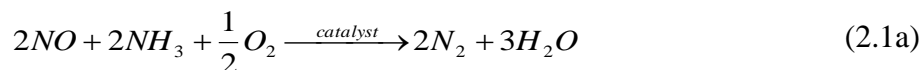
**Comment:** Page 2-8, Section 2.2.1: This section should note that although NO<sub>x</sub> is mostly NO, NO<sub>x</sub> is calculated as NO<sub>2</sub> for emissions purposes. Therefore, the major NO<sub>2</sub> reactions should also be included here. (see page 2-53).

**Response:** The EPA agrees with the commenter that NO<sub>x</sub> emission rates are generally expressed as pounds of NO<sub>2</sub> per MMBtu. However, we note that the majority of NO<sub>x</sub> in flue gas



from combustion units is NO. For clarification, the EPA has revised Section 2.1.1 to read as follows:

“The reducing agent employed by the majority of SCR systems is gas-phase ammonia (NH<sub>3</sub>) because it readily penetrates the catalyst pores. The ammonia, either in anhydrous or aqueous form, is vaporized before injection by a vaporizer. Within the appropriate temperature range, the gas-phase ammonia then decomposes into free radicals, including NH<sub>3</sub> and NH<sub>2</sub>. After a series of reactions, the ammonia radicals come into contact with the NO<sub>x</sub> and reduce it to N<sub>2</sub> and H<sub>2</sub>O. Since NO<sub>x</sub> includes both NO and NO<sub>2</sub>, the overall reactions with ammonia are as follows:



The equations indicate that one mole of NH<sub>3</sub> is required to remove one mole of NO and two moles of NH<sub>3</sub> are required to remove one mole of NO<sub>2</sub>. However, Equation 2.1a is the predominant reaction because 90 to 95% of NO<sub>x</sub> in flue gas from combustion units is NO. Hence, about one mole of NH<sub>3</sub> is required to remove one mole of NO<sub>x</sub>. The catalyst lowers the required activation energy for the reduction reaction and increases the reaction rate. In the catalytic reaction, activated sites on the catalyst rapidly adsorb ammonia and gas-phase NO<sub>x</sub> to form an activated complex. The catalytic reaction, represented by Equations 2.1a and 2.1b, result in nitrogen and water, which are then desorbed to the flue gas. The site at which the reaction occurs is then reactivated via oxidation.”

### *Catalyst*

#### **Commenter: Portland Cement Association**

#### **DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph in section 2.2.1 (Catalyst) be revised:

“Originally, SCR catalysts were precious metals such as platinum (Pt). In the late 1970s, Japanese researchers used base metals consisting of vanadium (V), titanium (Ti), and tungsten (W), which significantly reduced catalyst cost. In the 1980s, metal oxides such as titanium oxide (TiO<sub>2</sub>), zirconium oxide (ZrO<sub>2</sub>), vanadium pentoxide (V<sub>2</sub>O<sub>5</sub>), and silicon oxide (SiO<sub>2</sub>) were employed to broaden the reaction temperature range. Zeolites, crystalline alumina silicates, were also introduced for high temperature (675–1000°F; 360–540°C) applications; however, zeolites tended to be cost prohibitive. While low temperature catalyst formulations may be useful for some industrial applications, they are not suitable for utilization where the gas stream contains sulfur dioxide or sulfur trioxide, such as exists at many U.S. cement plants. From 1980 to 2008, the cost of catalyst has dropped from approximately \$34,000/m<sup>3</sup> to a range of \$5,000 to \$6,000/m<sup>3</sup> (costs are in 2011\$) [7b].<sup>10</sup>”

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<sup>10</sup> An earlier reference shows that from 1980 to 2006, the cost of catalyst dropped by 75% from approximately

**Response:** The EPA agrees that lower temperatures may have impacts on SO<sub>3</sub> concentration and this topic has been added elsewhere in the final revised chapter. The impact of the lower temperature on the formation of SO<sub>3</sub> across the SCR catalyst is discussed in section 2.2.2 under subsection “SO<sub>2</sub> and SO<sub>3</sub> concentrations in gas streams.”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to section 2.2.1 (Catalyst):

“Catalysts utilized in utility and industrial boilers are not readily transferrable to other applications such as cement kilns. Cement kilns have as much as 18 times the dust loading of a coal fired boiler. As a result, the size of the openings, pitch, of the catalyst must be larger. This reduces the surface area per unit volume, and may necessitate additional catalyst volume to meet emissions limits for NO<sub>x</sub> and ammonia slip. Also note that some cement plants have ammonia in the kiln exhaust gas without injecting any ammonia into the gas stream. Therefore, the ammonia slip from unreacted ammonia injected for SCR is difficult to differentiate from the natural fluctuations in ammonia in the stack gas. The contribution of trace elements from raw materials in a cement kiln exhaust is a significant difference from the normal emissions constituents from coal or gas combustion.”

**Response:** The EPA agrees that cement kilns generally have higher dust loading than coal-fired boilers and has noted this elsewhere in the final revised chapter. The impact of the higher dust loading on the selection of catalyst pitch seems to be more appropriately placed in section 2.2.2 under subsection “Catalyst Pitch”, and the following discussion for cement kilns has been included in that section in the final revised chapter. The following text was added:

“For high-dust applications, such as cement kilns, catalysts with larger openings, or pitch, should be used to reduce the potential for catalyst plugging. However, the wider pitch reduces the surface area per unit volume, and may necessitate additional catalyst volume to meet emissions limits for NO<sub>x</sub> and ammonia slip.”

With respect to the recommended revision for ammonia from raw materials, the EPA agrees that raw materials used at some cement kilns result in ammonia emissions that should be taken into account. This discussion and its relationship to ammonia slip may fit more appropriately in section 2.2.2 under subsection Ammonia Slip. The following text was added to the final revised chapter:

“Raw materials at some cement kilns contain constituents that release ammonia to the kiln gas stream when heated to high temperature. Some cement plants have ammonia in the kiln exhaust gas without injecting any ammonia into the gas stream. Therefore, the ammonia slip from unreacted ammonia injected for SNCR or SCR is difficult to differentiate from the natural fluctuations in ammonia in the stack gas. For this reason, it is important to understand the level of raw material derived ammonia emissions when designing an SCR control system for cement kilns.”

Trace elements from raw materials in cement kilns that may impact the catalyst activity seems to most appropriately be discussed in section 2.2.2 under subsection “Catalyst Deactivation”. A discussion of the types of trace compounds that may impact catalyst activity was added to the final revised chapter, as discussed in the response to another comment in Section 2.2.2 below.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph in section 2.2.1 (Catalyst) be revised as shown:

“Catalyst cleaning typically means the removal of physical restrictions to the catalyst (i.e., blinding layers and large particle ash [LPA]), rejuvenation means the removal of poisons without replenishing catalytically active compounds in the catalyst, and regeneration typically means the removal of poisons and the restoration of catalytic activity by restoring catalyst active ingredients [43]. These activities may occur online/in-situ or offline, and may occur onsite or offsite [43]. The catalyst layers may be removed and transported to the cleaning, rejuvenation, or regeneration site. Online catalyst cleaning with soot blowers or sonic horns is conducted on a regular basis to remove ash or particles (soot blowers and sonic horns are discussed below) [44]. Water-based cleaning can also be conducted to remove physical materials that plug or blind the catalyst [45]. Catalyst cleaning in cement plant applications requires continuous cleaning with compressed air. This more aggressive cleaning will result in a reduction of physical catalyst life and the number of times the catalysts used in cement plants can be reactivated compared to catalysts used in boilers.”

**Response:** The EPA agrees that discussion of catalyst cleaning for SCR in the cement industry should be included, and while the recommended addition has not been added to this specific section, discussion of catalyst cleaning with compressed air for the cement industry has been included in section 2.2.5 subsection Soot Blower or Sonic Horn.

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 2-11, Section 2.2.1: Improvements in one aspect of the SCR (NO<sub>x</sub> removal, ammonia slip, SO<sub>3</sub> production) will often result in deterioration in another. There is almost always a tradeoff and that should be noted here.

**Response:** It is true that there may be tradeoffs between certain aspects of the SCR operation, e.g., an increase in ammonia injection could lead to higher NO<sub>x</sub> removal rates but also increase ammonia slip. On the other hand, recent research and improvements in catalyst formulations have achieved both high NO<sub>x</sub> removal rates and low SO<sub>2</sub> conversion. For more information on optimizing SCR operation, see *Optimization of SCR Control Technology for Reduced NO<sub>x</sub> Emissions, Improved Performance, and Reduced Operating Expenses*, Final Report 09-09, New York State Energy Research and Development Authority (NYSERDA), April 2009.

### *Catalyst Price*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Based on our members' experience, the catalyst prices quoted Page 2-11 are too low. A more appropriate number is \$8,000 - \$10,000/m<sup>3</sup>. As an example, one of our member companies operates an SCR with three catalyst layers. The current operating program calls for replacing one of the three layers every 18-24 months, during the planned outage cycle. Thus, each layer achieves a 54-72 month functional life before regeneration or replacement. The labor cost for exchanging a layer is \$300,000 and the replacement cost for a new layer is approximately \$1,000,000; these costs occur every 18-24 months. The purchase of a used layer that can be regenerated is approximately \$650,000, but regeneration costs per layer range from \$400,000-500,000 depending on the type of catalyst and replenishment options selected. The ceramic base of the catalyst modules cannot be regenerated indefinitely, and may survive five regeneration cycles before requiring complete replacement. Most SCR users buy new catalyst and let the catalyst vendor take the old catalyst for regeneration, instead of regenerating catalyst themselves. Therefore, the cost of regeneration is typically incorporated into the cost of new catalyst.

**Response:** We thank the commenter for the information provided in their comment. A catalyst price of around \$8,000/m<sup>3</sup>, which is equal to \$226/ft<sup>3</sup>, or higher appears to be above what current prices are, according to information available to EPA. We use \$5,500/m<sup>3</sup> as a default for catalyst price based on information from a report by Cichanowicz in 2013 (reference 7b in the SCR Cost Manual chapter). If an up to date and reliable estimate of catalyst cost supplied by a vendor that can be documented is available for a cost estimate, then that estimate can be used in an analysis under the methodology in the Control Cost Manual.

We will reflect the other information provided by the commenter on catalyst users and vendors accordingly in the SCR Cost Manual chapter.

### *Regenerated Catalyst*

**Commenter:** San Joaquin Valley Air Pollution Control District

**DCN:** EPA-HQ-OAR-2015-0341-0027-A2

**Comment:** The following benefits of a regenerated catalyst should be added to Section 2.2.1 in Chapter 2 for SCR, based on information in the link [https://online.platts.com/pps/p=m&s=1029337384756.148827&e=1140211156928.3353357507452834748/?artnum=F2X00RF6VV0213A155358n\\_1](https://online.platts.com/pps/p=m&s=1029337384756.148827&e=1140211156928.3353357507452834748/?artnum=F2X00RF6VV0213A155358n_1):

- Low regeneration cost per layer as compared to replacement cost.
- No catalyst cost.
- Full restoration of original catalytic activity.
- Same deactivation rate as a new catalyst in the same SCR installation.
- Low SO<sub>2</sub> oxidation (SO<sub>2</sub>/SO<sub>3</sub> conversions is no higher than the new catalyst guarantee)

- Removal of 99% of physical restrictions, including flay ash plugging, large particle ash, and blinding layers.
- No physical damage to the catalyst and no loss of structural integrity.

**Response:** The Platts website suggested by the commenter links to a Power Engineering magazine February 2006 article. The revised SCR discussion of catalyst cleaning, rejuvenation, and regeneration are based on multiple references, some of which are more recent than the Feb 2006 article noted by the commenter. A Power Feb 2006 article notes the following: the catalyst life for regenerated catalyst is equal to or longer than the catalyst life of new catalyst; regeneration can fully restore the NO<sub>x</sub> catalyst activity, and by increasing the number of catalyst sites available, can increase the NO<sub>x</sub> catalyst activity from the original catalyst (by up to 25 percent); regenerated catalyst can achieve lower SO<sub>2</sub> to SO<sub>3</sub> conversion than new catalyst [cites an ongoing study in 2006 on SO<sub>2</sub> conversion, results are available in March 2006 article, see below]; lower regeneration cost per layer as compared to replacement cost; disposal costs range from \$50 to \$2,000 per ton, which translates into a savings of \$20,000 to \$500,000 per layer for a 500 MW unit if regenerated catalyst is used; the shipping cost for sending spent catalyst to a disposal site is approximately the same as shipping the catalyst to a regeneration facility; the cost of shipping regenerated catalyst back to the plant and the installation labor is approximately equal to shipping new catalyst to the plant and installing; the cost of new catalyst ranges from \$3,500 to \$4,500/m<sup>3</sup>, and the cost to regenerate catalyst is approximately 60 percent of new price; new catalyst costs from \$758,000 to \$975,000 per layer for a 500 MW unit, regenerated catalyst costs \$455,000 to \$585,000 per layer for a 500 MW unit, for a savings of \$303,000 to \$390,000 per layer. The Power Engineering March 2006 article discusses the results of the SO<sub>2</sub> conversion testing and notes the following: results of study to quantify SO<sub>2</sub> to SO<sub>3</sub> conversion of regenerated catalysts; honeycomb catalyst in the study had a baseline SO<sub>2</sub> conversion rate of 0.34 percent, and following SCR-Tech's regeneration process, had a conversion rate of 0.19 percent; plate catalyst in the study had a baseline SO<sub>2</sub> conversion rate of 0.45 percent, and following SCR-Tech's regeneration process had a conversion rate of 0.38 percent. It would be appropriate to conclude from this study that regeneration lowers the SO<sub>2</sub> oxidation for some catalysts.

- Lower regeneration cost per layer as compared to replacement cost. [[1] ICAC SCR 2009] [[48] Tate July 2008] [Platts, McMahon Feb 2006] [[44] Wicker June 2004]
- No catalyst cost. [[1]ICAC SCR 2009] [[48] Tate July 2008] [[44] Wicker June 2004]
- Disposal cost savings. [[1]ICAC SCR 2009] [Platts, McMahon Feb 2006] [[44] Wicker June 2004]
- Full restoration of original catalytic activity. [Platts, McMahon Feb 2006] [[50] Coalogix June 2011] [[45] STEAG Oct 2006]
- Same deactivation rate as a new catalyst in the same SCR installation, i.e., comparable equipment life as new catalyst. [Platts, McMahon Feb 2006] [[45] STEAG Oct 2006]
- Lower SO<sub>2</sub> oxidation for some catalysts (i.e., SO<sub>2</sub>/SO<sub>3</sub> conversions is no higher than the new catalyst guarantee) [Cooper March 2006] [[50] Coalogix June 2011]
- Removal of physical restrictions, including flay ash plugging, large particle ash, and blinding layers. This statement does not appear to be in the reference but was found in Hartenstein. [[43] Hartenstein Feb 2007]

- No physical damage to the catalyst and no loss of structural integrity. This statement does not appear to be in the Platts reference but was found in Hartenstein. [43] Hartenstein Feb 2007]

The EPA agrees with the commenter that there are additional benefits of regenerated catalyst beyond those already discussed in the section. The Platts web address provided links to a February 2006 article in Power Engineering magazine “Catalyst Regeneration: The Business Case” by B. McMahon. In its review of the article, the EPA could confirm information related to 3 of the suggested benefits, and the addition of one other bullet point related to catalyst disposal cost savings. Based on review of other data sources, the remaining suggested topics could also be confirmed. The commenter recommended text has been reviewed and included as follows:

“Benefits for regenerated catalysts include the following:

- Lower regeneration cost per layer as compared to replacement cost. [[1] ICAC SCR 2009]
- No catalyst cost. [[1]ICAC SCR 2009]
- Disposal cost savings. [[1]ICAC SCR 2009]
- Full restoration of original catalytic activity. [Platts, McMahon Feb 2006]
- Same deactivation rate as a new catalyst in the same SCR installation, i.e., comparable equipment life as new catalyst. [Platts, McMahon Feb 2006]
- Lower SO<sub>2</sub> oxidation for some catalysts (i.e., SO<sub>2</sub>/SO<sub>3</sub> conversions is no higher than the new catalyst guarantee) [[50] Coalogix June 2011]
- Removal of physical restrictions, including fly ash plugging, large particle ash, and blinding layers. [[43] Hartenstein Feb 2007]
- No physical damage to the catalyst and no loss of structural integrity. [[43] Hartenstein Feb 2007]”

## **2.2.2 SCR Performance Parameters**

### **Introduction paragraph**

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph in section 2.2.2 (SCR Performance Parameters) be revised as shown:

“The majority of the discussion regarding SNCR design and operational factors is valid for the SCR process, except for small variations due to the use of a catalyst and the reaction chamber being separate from the combustion unit. Additional design and operational factors to consider that are specific to the SCR process include the following:

- Catalyst activity;
- Catalyst selectivity;
- Pressure drop across the catalyst;

- Ash management (i.e., mitigating large particle ash (LPA) impacts on the catalyst);
- Dust loading
- Dust characteristics such as stickiness
- SO<sub>2</sub>/SO<sub>3</sub> concentrations in gas stream
- Catalyst pitch;
- Catalyst deactivation; and
- Catalyst management.”

**Response:** The EPA agrees with the commenter and has included the additional factors in the final revised chapter. Discussion of the design and operational factors for “Dust loading” and “Dust characteristics” have been included under the current “Ash management” discussion; the topic for “SO<sub>2</sub>/SO<sub>3</sub> concentrations in the gas stream” has been included as a new paragraph.

### *Temperature*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Page 2-13 states that the optimum temperature range for SCR is 480°F-800°F. While using an SCR at a temperature of 480°F may be possible, the optimum operational range begins at temperatures above 600°F. The data in Figures 2.2 and 2.3 supports this, showing a significant decrease in removal efficiency and increase in the volume of catalyst required at temperatures below 600°F.

**Response:** We agree that the temperature range of 480° to 800°F is a fairly wide range that is dependent on the catalyst type and is not reflective of a general optimum range. To clarify the appropriate temperature ranges for SCR, we have revised the final text to indicate that 480° to 800°F is an “operating” range, and have maintained the statement in the subsequent paragraph that the optimum temperature range is 700° to 750°F.

**Commenter:** Portland Cement Association

**DCN:** EPA-HQ-OAR-2015-0341-0023-A1

**Comment:** The commenter recommended the following paragraph in section 2.2.2 (SCR Performance Parameters - Temperature) be revised as shown:

“Because the optimum temperature window of the SCR process is lower than that of SNCR, the reagent injection into a reactor chamber occurs downstream of the combustion unit, rather than inside the combustion unit. As discussed previously, there are several options for the location of the SCR reactor. The flue gas temperature at each of these locations is different. Most designs install the reactor downstream of the economizer and prior to the air preheater, where the flue gas is at the appropriate temperature for metal oxide-based catalysts. Reheating of the flue gas may be required for reactors located downstream of the air preheater. Reheating significantly increases SCR operational costs. This continues to be true despite natural gas prices that are relatively low on an historical basis.<sup>6</sup> The costs for gas reheat associated with tail-end cement SCR systems may have a significant negative impact on the economic viability

for most, if not all, kilns. Cement markets are regional and localized. Cement plants compete on a cost per ton clinker basis. The additional cost for gas reheat may result in some kilns being unable to increase their cement pricing enough to cover the additional costs, both capital and operating for the SCR system.

Boiler operation at reduced loads decreases the gas flow rate. At reduced gas flow rates, the economizer outlet gas temperature decreases because boiler heat transfer surfaces absorb more heat from the flue gas. Typical SCR systems tolerate temperature fluctuations of  $\pm 200^{\circ}\text{F}$  ( $\pm 93^{\circ}\text{C}$ ) [33]. However, if significant  $\text{SO}_2$  is present in the gas stream, the gas must be continuously maintained above the temperatures of ABS formation and the overall energy efficiency of the SCR system will be affected . . .”

**Response:** The EPA disagrees with these suggested revisions and has not included in the final revised section. The Control Cost Manual is meant to provide guidance for consistent cost estimates and typically does not describe the economic impacts to individual industries from applying air pollution control measures. The  $\text{SO}_2$  conversion to  $\text{SO}_3$  and the formation of ammonium bisulfate (ABS) and ammonium sulfate are discussed in section 2.2.6, Other Considerations, under subsection “Formation of  $\text{SO}_x$ .” Additional discussion has not been included here.

### ***Stoichiometric Ratio***

**Commenter:** Arizona Public Service Company (APS)

**DCN:** EPA-HQ-OAR-2015-0341-0028-A1

**Comment:** Page 2-17, Section 2.2.2: A comment should be included that the 1.05 stoichiometric ratio is applied to total  $\text{NO}_x$  removal, not just the amount over 85 percent. Also, it should be noted that this is not ammonia slip, but the actual ammonia reacted due to the portion of  $\text{NO}_x$  that is  $\text{NO}_2$ . Ammonia slip is in addition to this.

**Response:** The EPA agrees with the commenter that the theoretical stoichiometric ratio is 1.05 because  $\text{NO}_x$  emissions includes approximately 95%  $\text{NO}$  and 5%  $\text{NO}_2$  and  $\text{NO}_2$  theoretically requires 2 moles of ammonia to each mole of  $\text{NO}_2$ . We also agree with the commenter that the ratio of 1.05 quoted in this section applies to the entire  $\text{NO}_x$  emissions and not just to the amount over 85%. For clarification, we have revised the discussion of the actual stoichiometric ratio as follows:

“The stoichiometric ratio factor (the moles of reagent injected per mole of  $\text{NO}_x$  removed) defines the quantity of reagent needed to achieve the targeted  $\text{NO}_x$  reduction. Theoretically, based on reaction equations 2.1(a) and (b), one mole of  $\text{NO}$  can be removed with one mole of ammonia and one mole of  $\text{NO}_2$  can be removed with two moles of ammonia. Since  $\text{NO}_x$  is mostly comprised of  $\text{NO}$  (approximately 95%), the theoretical stoichiometric ratio for  $\text{NO}_x$  is close to 1.05 mole of ammonia per mole of  $\text{NO}_x$ . Hence, SCR systems typically employ an actual stoichiometric ratio of 1.05 moles of ammonia per mole of  $\text{NO}_x$  to account for the small portion of  $\text{NO}_x$  that is  $\text{NO}_2$  [33]. This assumption of an almost one-to-one linear relationship between the quantity of reagent and the  $\text{NO}_x$  removed is good up to about 85%  $\text{NO}_x$  reduction [46]. Above 85%, the removal efficiency begins to level off and more than the theoretical amount of ammonia is required for additional  $\text{NO}_x$  removal because of reaction



rate limitations. Because capital and operating costs depend on the quantity of reagent consumed, the stoichiometric ratio is an important design parameter that is determined by the SCR designer.”

### ***Ammonia Slip***

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to Section 2.2.2 (SCR Performance Parameters – Ammonia Slip):

“At cement kilns, constituents in the raw materials can result in ammonia concentrations in the stack gases well above the 5-10 ppm slip that may result from SNCR or SCR systems. Concentrations above 50 ppm have been measured. It is important to note that the mechanisms for this ammonia formation occur after the ammonia injection location for SNCR, but would be in the gas stream prior to SCR applications and needs to be considered.”

**Response:** The EPA agrees that raw materials used at some cement kilns result in ammonia emissions that should be taken into account when designing an SCR control system. However, we have been unable to confirm the commenter’s statements regarding the level of ammonia emissions from raw materials and that ammonia derived from raw materials would be in the gas stream prior to the SCR. Therefore, we have included the following text in section 2.2.2 of the final version of the Chapter:

“Raw materials at some cement kilns contain constituents that release ammonia to the kiln gas stream when heated to high temperature. Some cement plants have ammonia in the kiln exhaust gas without injecting any ammonia into the gas stream. Therefore, the ammonia slip from unreacted ammonia injected for SCR is difficult to differentiate from the natural fluctuations in ammonia in the stack gas. For this reason, it is important to understand the level of raw material derived ammonia emissions when designing an SCR control system for cement kilns. [94]”

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 2-18, Section 2.2.2: The cost for ammonia monitoring appears to be based only on the incremental cost of the instrumentation and does not take into consideration the complete monitoring system. The chapter should be clear as to what equipment is included in this cost estimate.

**Response:** The costs cited in section 2.2.2 are the costs for purchasing an ammonia monitoring instrument and do not include other costs for ancillary equipment or installation. In general, an NH<sub>3</sub> monitor is not essential for operation of an SCR, however, they may be required by a permit if the unit is subject to an NH<sub>3</sub> limit. The capital and operating costs for monitoring systems must be estimated separately using the methodology presented in Section 2, Chapter 4 (Generic Equipment and Devices) of the Cost Manual.

## *Catalysts*

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to the end of Section 2.2.2 (SCR Performance Parameters – Catalyst Reaction Selectivity):

“In contrast, in cement plant applications, the fuel sulfur is incorporated into the clinker. However, pyritic sulfur in raw materials is oxidized and released into the kiln gas stream and as previously noted, ammonia may also be emitted from raw materials as they are heated. Close monitoring of the temperature of the gas stream prior to the SCR inlet and within the SCR is necessary.”

**Response:** The EPA agrees with the commenter that raw materials that contain pyritic sulfur used in cement kilns can be another source of sulfur. SO<sub>2</sub> can be as much as two orders of magnitude greater when pyritic sulfur is present in raw materials and will react with unreacted ammonia from the SCR process or from raw materials to produce ammonium sulfates. Fuel sulfur and raw material sulfur have been added to this section in the final revised chapter, and are also discussed in section 2.2.6 under subsection “Formation of SO<sub>x</sub>.” The discussion of ammonia from raw materials has not been included here because it has been discussed in section 2.2.2 under subsection for “Ammonia slip” in the final revised chapter.

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 2-19, Section 2.2.2: Catalyst reaction selectivity: A comment should be added that catalysts designed for lower SO<sub>2</sub> to SO<sub>3</sub> conversion also get lower NO<sub>x</sub> conversion.

**Response:** The EPA disagrees with the recommended revision and has not included it in the final revised section. While earlier work to reduce the conversion rate of SO<sub>2</sub> to SO<sub>3</sub> across the catalyst may have had some impacts on the NO<sub>x</sub> reduction rate, catalyst manufacturers and regenerated catalyst firms currently produce catalysts that maintain peak NO<sub>x</sub> conversion and that are also able to reduce SO<sub>2</sub> conversion across the catalyst layers. For additional information, see Morita, I., Y. Nagai, Y. Kato, H. Franklin, and J. Cooper, *Development and Operating Results of Low SO<sub>2</sub> to SO<sub>3</sub> Conversion Rate Catalyst for DeNO<sub>x</sub> Application*, [No Date]. See [http://www.psa.mhps.com/supportingdocs/forbus/hpsa/technical\\_papers/140.pdf](http://www.psa.mhps.com/supportingdocs/forbus/hpsa/technical_papers/140.pdf).

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph Section 2.2.2 (SCR Performance Parameters – Catalyst Deactivation):

“**Poisoning** – Certain fuel constituents that are released during combustion act as catalyst poisons. Certain raw material constituents at cement kilns also act as catalyst poisons. Catalyst poisons include calcium oxide, magnesium oxide, potassium, sodium, arsenic, chlorine, fluorine, and lead. Many of these poisons are found in cement kiln raw materials and the dust in the kiln gas stream. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them. Catalyst poisoning represents the main cause of catalyst

deactivation. The activity of poisoned catalysts may be restored by rejuvenation or regeneration.”

**Response:** The EPA agrees that some raw material constituents or trace elements may be catalyst poisons and has made the following revisions to this subsection:

**“Poisoning** – Certain fuel constituents that are released during combustion act as catalyst poisons. Catalyst poisons include calcium oxide, magnesium oxide, potassium, sodium, arsenic, chlorine, fluorine, and lead. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them. Catalyst poisoning represents the main cause of catalyst deactivation. The water soluble alkali compounds are known to react with active catalyst sites rendering them inert. The form of the alkali metals is important as water soluble alkali metals have been found to be more detrimental to catalyst activity.

Arsenic is a concern for boilers that reinject fly ash or burn coals that have moderate to high arsenic content with a free lime concentration in the ash of less than 2 percent. Some facilities have found it useful to inject limestone into the furnace. The calcium oxide reacts with arsenic to form calcium arsenate, which affectively removes the arsenic from the gas stream thereby preventing it from binding to catalyst and rendering them inactive [96]. The activity of poisoned catalysts may be restored by rejuvenation or regeneration.

In cement kilns, both the raw materials and the fuels can contain compounds that poison catalysts, including inorganic compounds of potassium, sodium, and chlorine. Alkali metal compounds in the raw materials have relatively low melting points and upon reaching the combustion zone of the kiln will readily volatilize. Although these compounds are also found in coal-fired boilers, they may be present in higher concentrations in cement kiln exhausts [94]. Catalyst poisoning by phosphorus, chromium, and lead compounds is believed to be a lesser concern for cement kilns than for coal-fired boilers [94]. These compounds are expected to be present in lower concentrations in cement kiln exhaust gases than is typical of coal-fired boilers [24, 94]. Arsenic poisoning is not expected to be an issue for cement plants because the high concentration of CaO should react with any arsenic in the exhaust gas before it reaches the SCR catalyst [96, 111]. However, high CaO levels combined with high sulfur concentrations can result in the formation of CaSO<sub>4</sub> in cement kilns, which can reduce catalyst activity through masking [94].”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph Section 2.2.2 (SCR Performance Parameters – Catalyst Formulation):

“To obtain the optimal catalyst formulation and SCR design for an application, the catalyst supplier and SCR vendor should be informed of the fuel constituents, such as sulfur, chlorine, fluorine, alkali, and trace metals. In cement kiln applications, the fuel and raw material constituents and gas constituents, must be identified. The SCR must be designed to operate for the full range of values for the constituent concentrations. Therefore, the ranges of these data must be provided to the vendor. In most cases the cement kiln should run a slip

stream pilot test for 6-12 months to determine if trace elements and dust characteristics are going to be compatible with the catalyst for long term performance. Even with pilot testing catalyst selection has proven to be a trial and error process for cement kilns. These fuel and ash constituents can be determined by chemical analyses. The associated analytical data can then be used to modify the catalyst composition to determine catalyst volume and design the SCR reactor components.”

**Response:** The EPA agrees that consideration of both fuel and raw material constituents are important considerations for any SCR application and has included similar statements in the final revised chapter. The commenter noted that a pilot test should be done on the catalyst, and while the EPA agrees that this could be done for most any SCR application, this has not been incorporated into the document. The following has been added:

“To obtain the optimal catalyst formulation and SCR design for an application, the catalyst supplier and SCR vendor should be informed of the fuel constituents and raw material constituents, such as sulfur, chlorine, fluorine, alkali, and trace metals. The SCR must be designed to operate for the full range of values for the constituent concentrations, therefore, the ranges of these data should be provided to the catalyst supplier. These fuel and ash constituents can be determined by chemical analyses. The associated analytical data can then be used to modify the catalyst composition to determine catalyst volume and design the SCR reactor components.”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph Section 2.2.2 (SCR Performance Parameters – Soot Blowers and Sonic Horns):

“**Soot Blowers and Sonic Horns** – Deposits on the surface of the catalyst can be dislodged by soot blowers, which are generally installed between each catalyst layer and operated on a periodic basis, such as once a week. A sonic horn is another option that prevents accumulation of ash deposits on the catalyst surface. A sonic horn may operate at a typical frequency of 10 seconds every 10 minutes [37]. In cement plant SCR applications continuous gas cleaning is necessary for the semi-dust and high dust SCR systems.”

**Response:** The EPA agrees that for some applications more frequent cleaning than periodic or weekly cleaning may be needed, for example, for the cement industry, continuous catalyst cleaning may be needed. The final revised chapter includes the following text:

“**Soot Blowers and Sonic Horns** – Deposits on the surface of the catalyst can be dislodged by soot blowers, which are generally installed between each catalyst layer and operated on a periodic basis, such as once a week. For some higher dust SCR systems, e.g., in the cement industry, more frequent and even continuous catalyst cleaning may be needed. A sonic horn is another option that prevents accumulation of ash deposits on the catalyst surface. A sonic horn may operate at a typical frequency of 10 seconds every 10 minutes [37].”

### ***Pressure Loss***

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to Section 2.2.2 (SCR Performance Parameters – Pressure Loss):

“Pressure loss in cement kiln SCR applications has been a problem. Where the dust loading in a boiler gas stream to the SCR may be 10-20 g/Nm<sup>3</sup>, in cement kiln applications they range from 80-180 g/Nm<sup>3</sup> or more. In addition, cement dust is stickier and harder to remove. These characteristics require more aggressive catalyst cleaning and catalysts with larger pitch and generally still result in higher pressure loss than desired. This translates to higher capital costs to add an additional ID fan or upgrade/replace the kiln ID fan, and increased power usage for the fan and for the compressed air catalyst cleaning systems. In addition, for a cement kiln, the increase in pressure loss translates to lower production rates and lower thermal efficiency. Reduced thermal efficiency increases fuel usage and increases fuel related emissions.”

**Response:** The EPA agrees with the commenter and has added the following paragraph to Section 2.2.2 (SCR Performance Parameters – Pressure Loss):

"Pressure loss may also be an issue in cement kiln SCR applications as the dust loading in cement kilns can be in excess of 80 g/Nm<sup>3</sup> [94]. In addition, cement dust can be sticky, creating residue buildups that can be difficult to remove, and generally result in higher pressure loss than observed in other industrial operations. As such, it may require additional catalyst cleaning and catalysts with larger pitch."

### ***Catalyst Management Plan***

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 2-21, Section 2.2.2: The five to seven year life must be based on ozone season use only or low dust installations. Additionally, this should be listed as operating hours rather than years.

**Response:**

The catalyst lifetime values in the original references [33] and [51] are provided in years. Reference [33] does not state whether the value is for ozone season or year round operation. As the commenter notes, the 5 to 7 year life may likely be that this longer catalyst lifetime is representative of a low dust configuration, or it could be representative for oil and gas operation. As a counterpoint to the ozone season use note, the example calculation in Reference [33] is based on 8,000 hr/yr, so year round operation is implied, and is based on a catalyst life guarantee of 24,000 hr (or 3 years).

Reference [51] provides cost estimates for cases with guaranteed catalyst life of 2 years, 4 years, and 6 years.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph in Section 2.2.2 (SCR Performance Parameters – Catalyst Management Plan) be revised as shown:

“A catalyst management plan (CMP), as described in a “saw-toothed” graphic shown in Figure 2.6, schedules periodic replacement of catalyst to maintain ammonia slip limits (this CMP has a maximum ammonia slip design value of 2 ppm [58]). In the past, CMP descriptions focused mainly on the catalyst replacement schedules; however, today, a CMP is a comprehensive catalyst management strategy that incorporates both SCR equipment management and catalyst management, along with attention to changes in regulatory requirements. This more comprehensive approach is needed with the move to year-round operation of SCRs for utilities or for cement kilns which operate continuously. While operation of SCR for compliance with the NO<sub>x</sub> SIP Call (1998) requirements typically called for ozone season operation only, year round operation is necessary to comply with more recent regulations (e.g., The Clean Air Interstate Rule (CAIR), 1999 Regional Haze Rule, an Ozone Transport Commission (OTC) initiative, and state rules such as the North Carolina (NC) Clean Smokestacks Rule that took effect in 2009 and the Texas requirements for the Houston area), to generate NO<sub>x</sub> credits, or to comply with settlement agreements with the U.S. EPA and Department of Justice. ...”

**Response:** The EPA agrees with the recommended text and believes this text is appropriate for all facilities that operate continuously. Therefore, the following text was included in the final revised chapter in section 2.2.2 subsection Catalyst Management Plan: “for facilities that operate continuously.”

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 2-23, Section 2.2.2: The listing of “2:1” should be shown as “2+1.”

**Response:** The EPA has seen in the literature both nomenclatures for describing the number of catalyst layers compared to the empty or spare layer number, i.e., “2:1” and “2+1”. We believe either is appropriate and conveys the information to the reader and have not made this change to the final revised section.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph in Section 2.2.2 (SCR Performance Parameters – Catalyst Management Plan) be revised as shown:

“Most CMPs call for the SCR reactor design to provide two or more layers filled with catalyst and one or more empty or spare catalyst layers (often called “2:1” design). When the initial catalyst layers deactivate to the point where ammonia slip reaches the maximum design value, the facility typically adds catalyst to the empty layer. Catalyst addition is managed.

There would likely be additional costs (e.g., due to lost generation or production) if a facility is unable to coordinate with planned unit outages.”

**Response:** The EPA agrees with the commenter’s suggestion and has included the revision in the final section, along with an additional revision. The following text has been added to section 2.2.2 subsection Catalyst Management Plan: “There would likely be additional costs or impacts (e.g., due to lost generation or production) if a facility is unable to coordinate with planned unit outages.”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to Section 2.2.2 (SCR Performance Parameters – Catalyst Management Plan):

“Little data exists for catalyst life for cement applications to date. In most instances the initial catalysts required replacement after short periods of operation to address dust plugging and excessive pressure drop issues and catalyst poisoning. The initial catalyst was replaced with either larger pitch or different shape openings. In addition, catalyst life and the number of times the catalyst can be regenerated may be impacted by the aggressive continuous cleaning methods.”

**Response:** The EPA has not included this specific recommended text in the chapter, and while this particular suggestion was not included, a similar statement made by the commenter in their next comment (see comment and response below) related to the catalyst life and regeneration has been added.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to the end of Section 2.2.2 (SCR Performance Parameters):

“Due to the significantly higher dust loadings (10-20 times that for boilers) catalyst management, particularly replacement frequency and regeneration will differ from utility, boiler and refinery applications.”

**Response:** The EPA agrees with the commenter that high-dust applications, such as those found in cement plants, may have different catalyst management plans than those for low-dust SCR applications. The dust loading levels noted by the commenter could not be confirmed and therefore were not included in the final chapter. However, the following text was added in section 2.2.2 subsection SCR Performance Parameters:

“For applications with higher dust loading, such as the dust loading typical of cement kilns, catalyst management plans may include more frequent catalyst replacement and regeneration schedules than would be typical for low-dust applications.”

### **2.2.3 SCR System Configurations**

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the title of Section 2.2.3 be revised as follows: “SCR System Configurations for Utility and Industrial Boilers”

**Response:** We disagree with the commenter’s recommendation that the title of Section 2.2.3 should be changed. This section of the Control Cost Manual provides information for SCR systems that is pertinent to a wide range of industrial applications, not just to utility and industrial boilers.

**Commenter: Sierra Club and National Parks Conservation Association**

**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** The discussion of tail-end SCRs is incomplete, citing only two references. EPA should conduct a comprehensive literature survey on this option, starting with the references cited and information presented in the following two reports prepared for the EPA: Fox (2011)<sup>11</sup> and Hartenstein (2010).<sup>12</sup> The proposed SCR chapter leaves the impression that tail-end SCRs are not yet commercially viable.<sup>13</sup> This is incorrect.

Tail-end SCRs have been successfully retrofitted on 10,000 MWs of coal-fired boilers in Germany.<sup>14</sup> The first tail-end SCR was installed in Germany in 1986 (Hamburg Hafen Generating Station Unit 1) and many others have been installed since then.<sup>15</sup> In total, about 40% of the retrofit SCRs in Europe are tail-end SCRs. The Electric Power Research Institute, EPRI, reported in 1989 that SCR was fully developed in two forms, as high-dust and as tail-end.<sup>16</sup> However, 15 years later the EPA is asserting the technology is not yet commercially available in its updated CCM SCR chapter. This oversight should be corrected.

These systems were mainly developed for use on cyclone-fired and other wet-bottom boilers because of their very high catalyst deactivation rates resulting from high arsenic levels in the flue gas. They were also widely applied in cases where space constraints and/or difficult retrofit issues would have caused long periods of downtime. Many of the currently uncontrolled coal-fired boilers in the U.S. fall into these categories, making tail-end units attractive options at many units in the U.S. today.

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<sup>11</sup> P. Fox, Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2, Final Report, Prepared for U.S. EPA, Region 8, March 2011, Available at: [https://www.rti.org/pubs/fox\\_report.pdf](https://www.rti.org/pubs/fox_report.pdf).

<sup>12</sup> Hans Hartenstein, On North Dakota Department of Health’s April 10, 2010 BACT Determination for Minnkota’s M.R. Young Station, On Behalf of the U. S. Department of Justice, April 2000, Available at:

<https://www.ndhealth.gov/aq/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/M.R.%20Young/Hartenstein%20Report%200708.pdf>.

<sup>13</sup> Proposal at pp. 2-26, 2-27.

<sup>14</sup> McIlvaine, Next Generation SCR Choices – High-Dust, Low-Dust and Tail-End, FGD and DeNOx Newsletter, January 2009, No. 369 (Ex. 1); H. Sobolewski, Hans Hartenstein, and H. Rhein, Steag’s Long-Term SCR Catalyst Operating Experience and Cost, EPRI SCR Workshop, Louisville, KY, November 2005 (Ex. 2).

<sup>15</sup> See, e.g., RileyPower, SCR Reference List of Tail End Units, June 15, 2007 (Ex. 3) and Ceram Low Dust Tail End Reference List, April 2009 (Ex. 4).

<sup>16</sup> United Engineers and Constructors, Technical Feasibility and Cost of SCR NOx Control in Utility Applications, RP 1256-8, Prepared for the Electric Power Research Institute, August 1989.



As a result of the extremely positive experience in Germany operating coal-fired boilers in cases where physical parameters of the flue gas (temperature, ash content) were unacceptable for high dust SCR or chemical composition of the flue gas resulted in rapid catalyst deactivation, tail-end systems were applied to many other high temperature combustion and other thermal processing applications including:

- Municipal solid waste incinerators (1989)
- Hazardous waste incinerators (1990)
- Sewage sludge incinerators (1990)
- Hospital and medical waste incinerators (1990)
- Crematories (1991)
- Pharmaceutical waste incinerators (1992)
- Refinery crackers (1994)
- Glass smelters (1994)
- Biomass furnaces (1994)
- Construction debris and waste wood combustors (1995)
- Electric arc furnaces (1996)
- Ammunition and chemical weapons incinerators (1997)
- Ethylene crackers (1997)
- Orimulsion boilers (1999)
- Roller mills (2000)
- Photovoltaic cell production (2002)
- Hydrogen reformers (2003)
- Steel coil heat treatment facilities (2003)
- Sintering plants (2003)
- Steel pickling (2005)<sup>17</sup>

In sum, almost every high NO<sub>x</sub> process has been successfully retrofitted with tail-end SCR, making the technology the most widely used secondary NO<sub>x</sub> reduction technology worldwide. Thus, the SCR chapter misinforms by giving short shrift to the tail-end option and suggesting it is not commercial, awaiting the development of “[n]ew low temperature catalysts.”<sup>18</sup> In fact, tail-end systems in Europe today operate at temperatures as low as 300°F. These low temperatures have been extremely successful for over a decade with minimal to no catalyst deactivation.<sup>19</sup> Low temperature catalysts also have been successfully retrofitted on gas turbines, ethylene cracker furnaces, and process heaters.<sup>20</sup> Further, there are many benefits of tail-end systems that are not even mentioned in the SCR chapter, including:

- Tail-end SCR allows fuel flexibility for the boiler, as activity and performance of the catalyst is almost independent of the fuel ash characteristics;
- Tail-end SCR avoids the occurrence of large particle ash issues and the cost of mitigating them;

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<sup>17</sup> Hartenstein 2010, p. A-13/14.

<sup>18</sup> Proposal at p. 2-27.

<sup>19</sup> Hartenstein 2010, p. A-18.

<sup>20</sup> C.P. Brundrett and others, Retrofit Application and Operation of the Shell Low Temperature SCR Technology on Gas Turbines, Ethylene Cracker Furnaces and Process Heaters, ICAC Forum 2002, February 12-13, 2002. ([Ex. 5](#))

- Tail-end SCR does not impact the load range of the boiler, while it is difficult to maintain minimum operating temperature with a high dust system, even when an economizer bypass is used;
- Lower catalyst temperatures lead to a smaller SCR reactor vessel and less catalyst, and thus lower capital costs;
- Tail-end SCR has a longer lifetime, considerably longer than 30 years, which would result in lower annual costs;
- Tail-end SCR is not integrated into an existing boiler structure, reducing retrofit costs and risks that are typically rolled into contingency and retrofit factors;
- Construction risk factors are lower as risks associated with prevalence and uncertainty of undergrounds in construction areas are minimized or eliminated;
- At congested plant sites where the SCR cannot be installed during normal maintenance outages, tail-end SCRs offer the advantage of shorter tie-in periods as they are at the tail end of the plant and thus construction does not affect plant operation, reducing unit downtime to accomplish tie-ins and avoiding outages required by hot-side, old equipment demolitions;
- Tail-end SCR maintenance costs are lower as clean flue gas flows through the reactors; and,
- Catalyst life is extremely long, greater than 100,000 hours for the German units,<sup>21</sup> four times longer than high dust SCRs.<sup>22</sup> In fact, several tail-end units on wet bottom boilers in Germany are still operating after 20 years with the initial catalyst fill and no replacement, exchange or addition.<sup>23</sup>

In sum, the higher operating costs from reheating the flue gas are often countered by higher capital costs and higher risks of hot side units. Thus, if EPA properly evaluated these and other benefits of tail-end SCRs, tail-end costs would frequently be comparable to those of high dust SCRs in many applications, especially those with significant space constraints or that use a low quality fuel, such as lignite. Given that most all of the ‘easy’ SCR retrofits in the U.S. have already occurred, many of the remaining uncontrolled units are more challenging applications that would be well-suited to tail-end systems. Thus, this section should be expanded, based on a thorough literature review, including recognition of European and Japanese experiences, and discussions with vendors of operating systems.

**Response:** We agree with the commenter that tail-end SCRs are a viable alternative to the high-dust and low-dust SCR configurations and acknowledge they have been used since the late 1980s. We also agree that tail-end SCRs have some advantages over these other configurations both in being easier to retrofit older units and allowing for greater flexibility both in the types of units that can be controlled and in the operation of those units. We also agree that some of the additional costs associated with installing and operating heaters are partially offset by other cost savings, including longer catalyst lifetimes and smaller quantities of catalyst. We also agree that catalysts designed to operate at lower temperatures, such as the Shell DeNOx and Johnson Matthey SINOX catalysts, have been available for many years and their use in tail-end SCRs

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<sup>21</sup> Hartenstein 2005 (Ex. 2).

<sup>22</sup> McIlvaine, January 2009 (Ex. 1).

<sup>23</sup> Hartenstein 2005 (Ex. 2); D. Borio and R. Babb, Technical and Economic Considerations in Hot or Cold Placement of SCR Systems for Utility Boilers, ICAC Forum '02 ([Ex. 6](#)).

helps lower the operating costs by reducing the amount of fuel used to reheat the gas stream. We have made the following revisions to the final revised chapter to clarify these points:

“The tail-end SCR configuration places the SCR reactor downstream of all air pollution control equipment installed on a unit. Figure 2.9 depicts a tail-end system for a plant with a particulate control device and a wet FGD system. The air pollution control equipment removes most flue gas constituents detrimental to SCR catalysts before the flue gas enters the SCR reactor. The tail-end SCR configuration is often a technically feasible alternative for situations where the high-dust SCR configuration is impractical [100].

Because the flue gas temperature at the tail end is below the range required for the  $\text{NH}_3/\text{NO}_x$  reaction, the flue gas needs to be reheated. Tail-end SCR systems use oil- or natural gas-fired duct burners or steam coil gas heaters for reheating. Some of the energy used to reheat the gas is recovered in a recuperating gas-to-gas heater. Some use catalysts specially designed for temperatures between 300 – 550°F and low pressure drops, which lowers the costs for flue gas reheating [103, 106, 107].

A tail-end system may have higher capital and operating costs than the other SCR systems because of the additional equipment and operational costs associated with flue gas reheating and heat recovery. However, these costs are in part offset by reductions in catalyst costs. Tail-end units require less catalyst because they can use catalysts with smaller pitch, which provide higher surface area per unit volume. Tail-end SCR typically require only 2 layers of catalyst [52], although some use four half-layers of catalyst to allow for greater flexibility for catalyst replacement [101]. In addition, because there is less fly ash, catalyst poisons, and  $\text{SO}_2$  in the flue gas for tail-end units, the catalyst lifetime is significantly increased and less expensive catalyst may be used. Some sources have reported catalyst lifetimes for tail-end SCRs to be over 100,000 hours [52, 100, 101]. The tail-end SCRs may also have longer lifetimes due to the lower temperatures.

Tail-end SCRs have been used since the late 1980s and were initially used on coal-fired power plants. They are currently used at a variety of different applications in Europe, Japan, and the U.S., including power plants, incinerators, refinery crackers, cement plants, and ethylene crackers [100, 101]. They have been installed on units burning a wide range of fuels, including fuels of variable composition, such as biomass (including wood waste and chicken litter), hazardous waste, municipal waste, and wastewater sludge [104, 105]. They are often easier and less complex to install than the high-dust and low-dust SCR configurations for retrofit situations and can be installed with less disruption to production. The tail-end SCR configuration has been used in many retrofits of existing power plants in Europe. In some situations, particularly where combustion units have space constraints, the capital cost for retrofitting high-dust SCRs may be higher than for tail-end SCR [52]. Modular tail-end SCR systems are also available that are designed to be installed with minimal plant disruption [102].

One other major advantage of the tail-end SCR configuration is that its preheater enables the SCR to operate independently of the combustion unit. This arrangement enables greater operating flexibility, allowing the combustion unit to operate in a wider range of operating loads and fuel types [100].”

The following references have been added to the end of the chapter:

[100] McIlvaine, Next Generation\_SCR Choices – High-Dust, Low-Dust and Tail-End, FGD and DeNO<sub>x</sub> Newsletter, No. 369, January 2009.

[101] H. Sobolewski, Hans Hartenstein, and H. Rhein, Steag's Long-Term SCR Catalyst Operating Experience and Cost, EPRI SCR Workshop, Louisville, KY, November 2005.

[102] Babcock Power, Inc. Product literature 2016. Available at <http://www.babcockpower.com/about>.

[103] C.P. Brundrett and others, Retrofit Application and Operation of the Shell Low Temperature SCR Technology on Gas Turbines, Ethylene Cracker Furnaces and Process Heaters, ICAC Forum 2002, February 12-13, 2002.

[104] Ibidem Ceram Environmental, Inc. Company literature 2009.

[105] Riley Power, Inc. Company literature 2007.

[106] van der Grift, C.J.G., A.F. Woldhuis, and O.L. Maaskant, “The Shell DeNO<sub>x</sub> System for Low Temperature NO<sub>x</sub> Removal,” Catalysis Today, Volume 27, Issues 1-2, January 1996.

[107] Johnson Matthey Catalysts LLC. Product Literature 2016. Available at [http://www.jmsec.com/Library/Brochures/Sinnox\\_Catalysts\\_for\\_Fossil\\_Fired\\_Power\\_Plants.pdf](http://www.jmsec.com/Library/Brochures/Sinnox_Catalysts_for_Fossil_Fired_Power_Plants.pdf).

**Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.**

**DCN: EPA-HQ-OAR-2015-0341-0022-A1**

**Comment:** Page 2-27 states that some combined-cycle gas turbines have SCR downstream of the heat recovery steam generator (HRSG), at temperatures in the 350°F-400°F range. It is not practical to retrofit such a unit in this manner. There is not sufficient space within the HRSG for the AIG and catalyst.

**Response:** For combined-cycle gas turbines, we agree with the commenter that SCR reactors are typically installed between the superheater and the evaporator within the HRSG, and not between the evaporator and the economizer as stated in the draft chapter. Most new HRSG units include a cavity designed to accommodate an SCR reactor. However, for older HRSG units, it can sometimes be difficult to find enough space to house the SCR reactor within the HRSG. Low-temperature SCRs can be fitted after the HRSG in situations where the SCR cannot be retrofitted inside the HRSG. We have made the following changes to the discussion of gas turbines in Section 2.2.3:

“Natural gas-fired turbine applications frequently use SCR technology for post-combustion NO<sub>x</sub> control. There are two basic gas turbine configurations: combined cycle (cogeneration cycle) and simple cycle. The majority of SCR systems are installed as combined cycle applications. As shown in Figure 2.10, a typical combined-cycle SCR design places the

reactor chamber within a cavity of the heat recovery steam generator system (HRSG), between the superheater and the evaporator. The flue gas temperature in this area is within the operating range for base metal catalysts. Most new HRSG units include a cavity designed to accommodate an SCR reactor. However, older HRSG units may not have sufficient space to house the SCR reactor within the HRSG. In these cases, a low-temperature SCR reactor may be installed after the HRSG. The high temperature SCRs used on simple-cycle turbines are generally not retrofitted to combined cycle turbines equipped with HRSG due to lack of space between the turbine and the HRSG [95, 96, 97]. Simple-cycle applications of SCR place the reactor chamber directly at the turbine exhaust, where the flue gas temperature is in the range of 850°F to 1000°F (450–540°C). This requires the use of a high-temperature catalyst such as zeolite [42].

We added the following references to the end of the chapter:

- [95] Northeast States for Coordinated Air Use Management (NESCAUM), “Status Report on NO<sub>x</sub> Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines, Technologies and Cost Effectiveness,” December 2000. Available at [www.nescaum.org/documents/nox-2000.pdf/](http://www.nescaum.org/documents/nox-2000.pdf/).
- [96] Institute of Clean Air Companies (ICAC), “White Paper: Selective Catalytic Reduction (SCR) Control of NO<sub>x</sub> Emissions from Fossil Fuel-Fired Electric Power Plants,” May 2009. Available at [http://c.ymcdn.com/sites/www.icac.com/resource/resmgr/Standards\\_WhitePapers/SCR\\_WhitePaper\\_final\\_2009.pdf?hhSearchTerms=%22Selective+and+Catalytic+and+Reduction+and+white+and+paper%22](http://c.ymcdn.com/sites/www.icac.com/resource/resmgr/Standards_WhitePapers/SCR_WhitePaper_final_2009.pdf?hhSearchTerms=%22Selective+and+Catalytic+and+Reduction+and+white+and+paper%22).
- [97] Boyce, M.P., “Gas Turbine Engineering Handbook,” Fourth Edition, Elsevier, 2012.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following paragraph be added to Section 2.2.3 after the discussion of turbines:

“Cement Kilns

Cement kiln applications are limited to a handful of currently operating systems in Europe and only one in the U.S. There is one tail-end SCR system, two semi-dust SCR systems (one is the U.S SCR system which is on a long dry kiln system) which first pass the kiln gas through a high temperature electrostatic precipitator, then the SCR and finally may pass through a baghouse for final particulate emissions compliance. One SCR system on a small LEPOL kiln with low dust loading (1-5 g/Nm<sup>3</sup>). The remaining systems currently known to be in operation are high dust systems on preheater and precalciner kilns.”

**Response:** In response to this comment, we have added the following paragraphs to Section 2.2.3.

“Cement Kilns:

SCR systems applied to cement kilns can have “tail-end”, “three “high-dust” SCR systems<sup>24</sup>, three “low-dust” SCRs<sup>25</sup>, and one “tail-end” SCR<sup>26</sup> are known. The “high-dust” SCRs reportedly achieve control efficiencies of approximately 80% with inlet dust loading of up to 100 g/m<sup>3</sup>. The “low-dust” SCRs are reported to have dust loadings less than 20 mg/m<sup>3</sup>, while the inlet dust loading for the Mannersdorf “tail-end” SCR is reported to be less than 10 g/m<sup>3</sup> [94, 98, 99]”

We added the following references to the end of the chapter:

- [94] U.S. Environmental Protection Agency, “Alternative Control Techniques Document Update – NOx Emissions Controls for New Cement Kilns,” EPA-453/R-07-006, November 2007.
- [98] Kline, John, “Is SCR Technology Coming (Back) to Cement?”, presentation by John Kline Consulting, April 2013. (<http://www.slideshare.net/jporterklaine/is-scr-technology-coming-back-to-cement>).
- [99] EKomeri, Offshore and Energy Information and Technologies, “Semi-Dust SCR at Mannersdorf,” October 21, 2015. Available at <http://www.ekomeri.com/semi-dust-scr-mannersdorf/>.

**Commenter: Portland Cement Association**

**DCN: EPA-HO-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revision to the discussion of SCR Reactor Designs in Section 2.2.3:

“In-duct (inline) SCR systems house the reactor within the plant’s existing ductwork rather than in a separate reactor chamber. The ductwork is generally enlarged to provide sufficient room for the catalyst. In-duct systems save on costs for the ductwork, reactor chamber, and induced draft (ID) fan. In-duct designs limit catalyst volume and mixing length; therefore, they are commonly used in conjunction with other NO<sub>x</sub> control technologies [41].

...

Reactor designs in cement are full scale SCR design with multiple catalyst layers and extensive catalyst cleaning systems.”

<sup>24</sup> The first “high-dust” configuration SCR was installed on a preheater cement kiln at the Solnhofer Zementwerkes in Germany in 2001 and operated until 2006. Two other “High-dust” SCRs have been installed on preheater cement kilns at the Mergelstetten plant in Germany in 2010 and The Cementeria di Monselice plant in Bergamo, Italy was installed in 2006.

<sup>25</sup> “Low-dust” configuration SCRs have been installed at the Sarche plant in Italy (2007), the Mannersdorf plant in Austria (2012), and the Joppa plant in the USA (2013). The Mannersdorf SCR is installed on a preheater cement kiln, while the Joppa SCR is installed on a long dry kiln. Both plants use an electrostatic precipitator to reduce particulate emissions entering the SCR. The Sarchi SCR is installed on a small Polysius Lepol kiln with no particulate controls, but low dust loading (reportedly less than 15 g/m<sup>3</sup>).

<sup>26</sup> The Rohrdorf plant in Germany installed a “tail-end” SCR in 2011 on a preheater kiln.

**Response:** We agree with the commenter that SCR systems used on cement kilns are full scale reactors, rather than in-duct SCRs. The SCRs installed on cement kilns have used multiple catalyst layers and catalyst cleaning systems. We have made the following revisions to the section on SCR reactor design in Section 2.2.3:

“Cement kilns have also used full scale SCR reactors, rather than in-duct SCRs. The SCRs used for cement kilns have typically consisted of multiple catalyst layers and extensive catalyst cleaning systems. For example, the SCR systems installed at the Solnhofen cement plant in Germany and the Cementeria di Monselice plant in Italy used reactors with six catalyst layers, although only three layers were in use at a time [94].”

The following reference was added to the end of the chapter:

[94] U.S. Environmental Protection Agency, “Alternative Control Techniques Document Update – NO<sub>x</sub> Emissions Controls for New Cement Kilns,” EPA-453/R-07-006, November 2007.

#### **2.2.4 SCR System Primary Equipment**

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.4:

“The majority of utility and boiler SCR designs use Thermal DeNO<sub>x</sub>®, an ammonia-based NO<sub>x</sub> reduction system developed and patented by Exxon Research and Engineering Company in 1975. An SCR system consists of five basic steps:

- Receive and store the ammonia (or the urea reactant, followed by onsite ammonia production);
- Vaporize the ammonia and mix it with air;
- Inject the ammonia/air mixture at appropriate locations;
- Mix the ammonia/air with flue gas; and
- Diffuse the reactants into the catalyst and reduce the NO<sub>x</sub>.

Although the basic steps in an SCR system are similar for all configurations, the system design and equipment specifications are somewhat different. A discussion of the SCR system design and equipment is given below for an ammonia reagent, high-dust, full reactor SCR for a 120 MW (approximately 1,200 MMBtu/hr) coal-burning utility boiler. The SCR process steps, related auxiliary equipment, and the potential impacts of SCR operation on existing plant equipment are also discussed. Simplified system flow schematics are presented in Figure 2.1 and Figure 2.7, and a list of equipment is presented in Table 2.3. Note that additional catalyst cleaning equipment including heated, dry, compressed air systems are required for cement kiln applications.”



**Response:** We have not incorporated the commenter’s recommendation to add “utility and boiler” to the first sentence. Based on our review of available data, we believe most SCR<sub>s</sub> are based on the Thermal DeNO<sub>x</sub>®.

We agree with the commenter that catalyst cleaning equipment is necessary for any high dust application, including SCR<sub>s</sub> used to control NO<sub>x</sub> emissions from cement kilns. We have made the following changes to Section 2.2.4:

“Although the basic steps in an SCR system are similar for all configurations, the system design and equipment specifications are somewhat different. A discussion of the SCR system design and equipment is given below for an ammonia reagent, high-dust, full reactor SCR for a 120 MW (approximately 1,200 MMBtu/hr) coal-burning utility boiler. These discussions are also pertinent to industrial applications. For example, cement kilns operating in the high-dust configuration would also require catalyst cleaning equipment [94]. The SCR process steps, related auxiliary equipment, and the potential impacts of SCR operation on existing plant equipment are also discussed. Simplified system flow schematics are presented in Figure 2.1 and Figure 2.7, and a list of equipment is presented in Table 2.3.”

The following reference was added to the end of the chapter:

- [94] U.S. Environmental Protection Agency, “Alternative Control Techniques Document Update – NO<sub>x</sub> Emissions Controls for New Cement Kilns,” EPA-453/R-07-006, November 2007.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.4 (Reagent Production, Storage, and Vaporization):

“As discussed previously, one of several reagents may be used in an SCR system, including anhydrous ammonia, aqueous ammonia, or urea. In the past, reagents have typically been purchased and stored before vaporization and use in the SCR. Ammonia (both anhydrous and aqueous) is the type of reagent most often used in SCR systems. Of about 230 utility boilers for which reagent type was reported in response to a survey in 2009, about 80 percent used ammonia, and 20 percent used urea [4]. U.S. cement plants typically utilize 19% aqueous ammonia for SNCR systems and likely would use the same type of system for SCR applications. Urea reagent is mostly used in SNCR systems [65]. Another option that some facilities have recently adopted is to produce ammonia onsite from urea feedstock. The onsite ammonia production system may reduce or eliminate ammonia shipping, handling, and onsite storage. Load following by the onsite ammonia production system is extremely important for the proper operation of the SCR. . . .

SCR applications on large boilers generally require one to five tanks with volumes ranging from 10,000 to 20,000 gallons per tank to maintain sufficient volume for 1–3 weeks of SCR operations. The ammonia storage tank may be sized for 3–30 days of storage. The high end of the range would be used in conservative design practice. Alternatively, if ammonia distributors are located nearby and considered reliable, the plant owner might opt



for a smaller tank, sized for fewer days of ammonia storage. Cement plant SCR applications typically utilize one ammonia tank of approximately 20,000 gallons.”

**Response:** We agree with the commenter that U.S. cement plants typically use 19% aqueous ammonia as the reagent for SNCR and have revised Section 2.2.4 as shown below. We were unable to confirm the size of reagent storage tanks used by cement plant and therefore, have not made the suggested revisions to the second paragraph. The size of the reagent storage tank is likely affected by several site-specific factors, including type and concentration of reagent, reagent usage rate, and how much space is available.

Section 2.2.4 was revised to read:

“As discussed previously, one of several reagents may be used in an SCR system, including anhydrous ammonia, aqueous ammonia, or urea. In the past, reagents have typically been purchased and stored before vaporization and use in the SCR. Ammonia (both anhydrous and aqueous) is the type of reagent most often used in SCR systems. Of about 230 utility boilers for which reagent type was reported in response to a survey in 2009, about 80 percent used ammonia, and 20 percent used urea [4]. Urea reagent is mostly used in SNCR systems [65], however, U.S. cement plants typically use 19% aqueous ammonia for SNCR systems and likely would use the same reagent for SCR applications.”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.4 (Onsite Urea-Derived Ammonia Production):

“One of the urea-derived ammonia production systems decomposes urea to generate ammonia that is fed to the AIG, as shown in Figure 2.12. The system consists of a blower, decomposition chamber, urea storage, chemical pumping system, and process controls. In the urea storage and pumping system, dry urea from the storage tank is mixed in a solution tank with water and transferred to an aqueous urea solution storage tank. Filtered ambient air is fed into the decomposition chamber through the use of a blower with automatic dampers to control discharge flow and pressure. In the chamber, a burner is fired downstream of the dampers, and an aqueous urea solution that is supplied by the storage and pumping system is sprayed into the post combustion gases by injectors. The decomposition occurs under a specific temperature and residence time, with the decomposition temperature ranging from 600 to 1000°F (320–540°C), and the urea is decomposed to ammonia and isocyanic acid. The outlet ammonia stream from the decomposition chamber feeds into the AIG system for the SCR [68].”

**Response:** The EPA agrees with the commenter’s suggestion and has included this revision in the final version.

## **2.2.5 SCR System Auxiliary Equipment**

### **Ductwork**

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.5 (SCR Inlet and Outlet Ductwork):

“In retrofit installations, new ductwork is required to integrate the SCR system with the existing equipment. In high-dust boiler SCR systems, the reactor is located between the economizer outlet and the air heater inlet. In high dust cement plant SCR applications, the reactor is between the kiln and the gas conditioning tower. In semi-dust cement SCR, the kiln gas first passes through a high temperature ESP before entering the reactor which may be followed by a baghouse. In low-dust boiler SCR systems, the SCR reactor is located between the outlet duct of the particulate control device and the air heater inlet duct. In tail-end boiler SCR systems, the ductwork tie-ins are downstream of the FGD system and also require the integration of the flue gas reheating equipment. See Section 2, Generic Equipment and Devices and Chapter 1, Hoods, Ductwork, and Stacks, for more details for boiler SCR. For tail-end, cement plant SCR the reactor is placed after the baghouse and gas reheat through the use of one or more heat exchange systems as well as additional duct burners may be required.”

**Response:** The EPA agrees with statements recommended by the commenter, however a similar configuration discussion has been included in section 2.2.3 SCR System Configurations and has not been added here. Characterization of this discussion as being applicable to utility and industrial boilers has been added to the final revised chapter. The addition of the “boiler only” applicability to Section 2, Chapter 1 was not included, as this essentially narrows the applicability of the costs for ductwork, and these ductwork costs would be applicable to both boiler and cement kiln SCRs along with other unit types as well.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.5 (SCR Bypass Duct):

“Low-load boiler operations can decrease the temperature at the SCR reactor inlet below the SCR operating range. In addition, startup and shutdown of the boiler causes drastic temperature fluctuations. For these operating conditions, an SCR bypass may (but not necessarily) be required to route the flue gas around the reactor chamber. The bypass is required for cement plant applications. During periods of startup and shutdown the operating temperatures and constituents in the kiln gases are not conducive to acceptable SCR operating conditions and will cause catalyst plugging or damage which could be severe enough to cause catalyst replacement. The bypass prevents catalyst poisoning and fouling during periods when flue gas stream conditions do not meet design specifications for proper SCR operation. The bypass system also must include zero-leakage dampers to prevent flue gas leakage from poisoning and fouling the catalyst while the SCR is not operating. A bypass system may also be considered for seasonal operation of the SCR system, such as for boilers that would require

NO<sub>x</sub> control during the ozone season (typically May to September), but not at other times of the year.”

**Response:** The EPA agrees with the commenter that bypass may be needed and has revised the section. The SCR bypass language for cement kiln SCRs has been added as a new paragraph rather than integrating into the current paragraph and reads as follows:

“An SCR bypass may be needed for cement plant applications. During periods of startup and shutdown, the operating temperatures and constituents in the kiln gases may affect SCR operating conditions and may cause catalyst plugging or damage.”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.5 (Soot Blower or Sonic Horn):

“Retractable rake-type soot blowers that use steam or air for blowing are used in SCR designs. The soot blowers are typically located above each catalyst layer. Soot blowing is usually performed on one catalyst layer or part of one catalyst layer at a time. Soot blowing of all the catalyst layers takes 30 minutes to 2 hours, but is usually done infrequently. In European SCR installations, soot blowing is done approximately once or twice a week [72]. Traveling-rake steam soot blowers can have installed costs of \$120,000–\$160,000 [37]. In cement applications heated dry compressed air catalyst cleaning systems are necessary. In addition, manual removal of dust buildup on the catalyst may also be necessary.”

**Response:** The EPA agrees that discussion of soot blowers and sonic horns for the cement industry should be included under this subsection. Discussion of manual cleaning of the catalyst has not been included here, however, catalyst cleaning in general is discussed in section 2.2.1 subsection Catalyst, where catalyst cleaning, rejuvenation, and regeneration are discussed in more detail (e.g., either in situ or offline, onsite or offsite). Soot blowing and sonic horns would be considered a subset of catalyst cleaning. The following text has been added to section 2.2.5 subsection Soot Blower or Sonic Horn:

“For high dust loadings, the cement industry also reports use of soot blowers using heated, dry compressed air and use of sonic horns [94]. Improvements to cement dust cleaning for high dust loading and sticky dust have been made by changing the geometry and operating parameters of the dust blowers [112].”

The following reference was added to the end of the chapter:

[112] CEMCat. Cement specific dust cleaning. January 2011. Vendor news. Available at: [http://elex-cemcat.com/news\\_en/](http://elex-cemcat.com/news_en/)

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.5 (Large Particle Ash (LPA) Equipment):

“A significant concern for boiler SCR operation that was not evident in early applications is the role of the accumulation of LPA, also referred to as “popcorn ash,” on catalyst surfaces of high- dust SCR applications. LPA is defined as particles that are 4–7 mm in characteristic dimension and large enough to lodge in the openings of grid- or plate-type catalysts [37]. It is estimated that up to half of SCR units on coal-fired utility boilers are affected by LPA [8]. LPA is not an issue for natural gas-fired applications.”

**Response:** The EPA agrees with the commenter and has revised the section to include the suggested revision.

“A significant concern for utility and industrial boiler SCR operation that was not evident in early applications is the role . . .”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to Section 2.2.5 (Upgraded or New Induced Draft (ID) Fan):

“The new ductwork and the SCR reactor’s catalyst layers decrease the flue gas pressure. To maintain the same flow rate through the duct work, additional energy is required. The existing ID fan may be unable to provide the required increase in static pressure. In such cases, an upgraded or new ID fan is installed. This is especially true for cement kiln applications due to the high dust loading and high pressure drop across the SCR. . . .”

**Response:** The EPA agrees with the commenter and has revised the section to include the following text:

“This is also true for cement kiln applications due to the high dust loading and high pressure drop across the SCR.”

## **2.2.6 Other Considerations**

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following sentence be added to Section 2.2.6 (Fuel Source):

“In cement plant applications the constituents in the raw materials play an even greater role in the SCR design than kiln fuels.”

**Response:** While there is certainly merit in the statement that the raw materials impact the operation of the kiln and the design of the SCR, EPA did not included this particular statement in the “Fuel Source” paragraph in the final revised chapter. A similar discussion of raw material

impacts for SCRs on cement kilns has been added in section 2.2.2 in subsection Catalyst Deactivation, subparagraph for “Poisoning” in the final revised chapter, and also in section 2.2.6 subsection Formation of SO<sub>x</sub>.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following sentence be added to Section 2.2.6 (Formation of SO<sub>x</sub>):

“Sulfur trioxide (SO<sub>3</sub>) forms during the combustion of fuels that contain sulfur, and additional SO<sub>3</sub> is formed over the SCR catalyst. In cement plants, the fuel sulfur is incorporated into the clinker. However, the raw material sulfur can be a significant source of SO<sub>2</sub> and SO<sub>3</sub> in the gas stream. SO<sub>3</sub> reacts with ammonia in the flue gas downstream of the reactor (ammonia slip) to form ammonium bisulfate (NH<sub>4</sub>HSO<sub>4</sub>) and ammonium sulfate [(NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>].”

**Response:** The EPA agrees with the commenter and has revised the section to include the following text:

“In cement plants, the fuel sulfur is incorporated into the clinker, however, the raw material sulfur can be a source of SO<sub>2</sub> and SO<sub>3</sub> in the gas stream.”

**Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.**

**DCN: EPA-HQ-OAR-2015-0341-0022-A1**

**Comment:** The costing equations include the possibility for air preheater modifications for SO<sub>3</sub> control for burning high-sulfur coal. Sulfur trioxide can form during combustion of fuels that contain sulfur, and additional SO<sub>3</sub> can form over the catalyst. Page 2-39 states that the amount of SO<sub>3</sub> formed across the SCR depends on the sulfur content of the fuel, the amount of ammonia slip, and the SCR temperature. However, the text fails to note that the catalyst formulation and activity are key factors in the oxidation of SO<sub>2</sub> to SO<sub>3</sub>. The text also suggests replacing the cold-end baskets of the air heater with enamel coated baskets, but that only applies to utility boilers with Ljungstrom-type air heaters, and not to industrial boilers.

**Response:** The EPA agrees the catalyst formulation and activity are appropriate factors to include. These factors have been added to the paragraph in the final revised chapter. While the commenter notes that there is no information in the text regarding impact of catalyst formulation and activity, there is an existing sentence on p.2- 44“Mitigation of SO<sub>3</sub> formation from oxidation of SO<sub>2</sub> on the catalyst has evolved to be of equal importance to NO<sub>x</sub> control in SCR design [37]. Catalysts designed for low SO<sub>2</sub> oxidation have been developed ...”

We also agree that use of enamel coated baskets applies only to Ljungstrom air preheaters used in large boilers and does not apply to other types of air preheaters. Although the Ljungstrom air preheaters are commonly used in electric power generating plants, they have also been used on

large industrial boilers and waste incinerators.<sup>27</sup> For clarification, we have made the following revisions to section 2.2.6:

“Elevated SO<sub>3</sub> concentrations raise the acid dew point of the flue gas. This phenomenon potentially leads to more corrosion on the air heater’s cold-end surfaces if the flue gas temperature is below the acid dew point. For Ljungstrom<sup>®</sup> preheaters the cold-end baskets of the air heater can be replaced with enamel-coated baskets to protect against this possibility.”

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 2-39, Section 2.2.6: Sulfur trioxide (SO<sub>3</sub>) is an emission concern for low sulfur coal. The significant increase level for sulfuric acid mist (SAM) is very low, so if there is little SO<sub>3</sub> initially and there is an increase from the conversion in the SCR, the opportunity to reduce SO<sub>3</sub> is limited. For example, consider two boilers. The low SO<sub>3</sub> boiler produces 3 tpy SAM; the high SO<sub>3</sub> boiler produces 20 tpy SAM. A new SCR adds 20 tpy to each. Assume adding dry sorbent injection (DSI) reduced SAM by 40%. The low sulfur boiler ends up with  $(3 + 20) \times (100\% - 40\%) = 13.8$  tpy, a 10.8 tpy increase. The higher sulfur boiler ends up with  $(20 + 20) \times (100\% - 40\%) = 24.0$  tpy, on a 4 tpy increase.

**Response:** The EPA agrees with the commenter that SO<sub>3</sub> is a concern for low sulfur coal and has added this statement to section 2.2.6 subsection Formation of SO<sub>x</sub> in the final revised chapter.

While the arithmetic computations in the comment are correct, the assumptions used for the commenter’s analysis and subsequent conclusion are incorrect. The generation of SO<sub>3</sub> (which leads to ammonium bisulfate (ABS)) is a fixed percentage across the SCR reactor – usually 1-3% of SO<sub>2</sub> entering is converted to SO<sub>3</sub>. Consequently, an SCR added to each unit cannot result in the same ABS increase (measured in tpy) for both units. The Agency notes that the proper catalyst formulation can reduce the conversion percentage. The combustion within the boiler’s furnace typically converts 1% SO<sub>2</sub> to SO<sub>3</sub>. Consequently, an increase of 800% ABS is not possible (an increase from 3 tpy to 20 tpy).

**Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.**

**DCN: EPA-HQ-OAR-2015-0341-0022-A1**

**Comment:** The final paragraph on page 2-39 states that oxidation of SO<sub>2</sub> to SO<sub>3</sub> across the SCR is a concern for boilers firing fuel with 2% or higher sulfur. However, the equation for air preheater costs uses a threshold of coal having 3 lb/MMBtu SO<sub>2</sub>, or greater. The coal does not contain SO<sub>2</sub>; it contains sulfur, which oxidizes to form SO<sub>2</sub> and SO<sub>3</sub>. It is not clear whether the choice of factor should be based on the sulfur content of the coal or the maximum equivalent SO<sub>2</sub> emission rate expected.

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<sup>27</sup> Arvos Group, Ljungstrom Division, Product literature, <http://www.arvos-group.com/divisions/ljungstroem/products/> (accessed March 8, 2016).

**Response:** The EPA agrees with the commenter and has revised the factor discussion for the APHC for coal-fired units. The SO<sub>2</sub> threshold of 3 lb/MMBtu is consistent with the IPM methodology to determine whether an APH modification is necessary. The second sentence in both Air Pre-heater Modification costs subsections of sections 2.4.1.1 and 2.4.1.3 have been revised as follows: “An air Pre-heater modification is necessary for the control of SO<sub>3</sub> for boilers that burn bituminous coal where the SO<sub>2</sub> content in the outlet stream from the boiler is 3 lb/MMBtu or greater.”

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Page 2-40 includes a discussion of using reagents for SO<sub>3</sub> control, and notes that they can cost more than replacement catalyst. However, these costs do not appear to be captured in the cost estimate and are not part of the capital cost captured in the air preheater cost (APHC) on page 2-58 and yet they represent significant annual cost.

**Response:** The EPA has no cost information on the increase in catalyst requirements or for the use of reagents to control, we simply note in the final revised chapter that their use can impact the TCI and TAC. More information related to use of SO<sub>2</sub>/SO<sub>3</sub> reagents can be found in Moretti, A., and R. Triscori, D. Ritzenthaler, *A System Approach to SO<sub>3</sub> Mitigation*, Presented at EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control, Mega Symposium, August 2006.

**Commenter:** Portland Cement Association

**DCN:** EPA-HQ-OAR-2015-0341-0023-A1

**Comment:** The commenter recommended the following sentence be added to the end of the discussion of Formation of Arsenic Oxide in Section 2.2.6:

“A significant portion (approximately 85%) of the dust in cement kiln gases is CaO.”

**Response:** The EPA agrees with the commenter that the exhaust stream from cement kilns contains CaO from raw materials and the process activity and has revised the section, however, the percentage could not be confirmed. The final revised chapter includes the following:

“For the cement industry, a significant portion of the dust in cement kiln gases is CaO.”

**Commenter:** Florida Department of Environmental Protection

**DCN:** EPA-HQ-OAR-2015-0341-0019-A2

**Comment:** Encouraged the EPA to consider including the use of SCR for the removal of dioxins and furans (D/F) from exhaust streams (particularly waste incineration) in the co-benefits section. Commenter provided some examples/case studies that show SCR can be an effective control technology for D/F emissions. The commenter suggested a discussion similar to the one provided for mercury control be added.

**Response:** EPA agrees with the commenter that SCR is a demonstrated control technology for dioxins and furans. We have added the following subsection to section 2.2.6:

***“Dioxin/furan control***

Dioxins and furans are emitted from combustion processes like waste incineration, burning fuels like wood, coal, or oil, and even from forest fires. Other processes, like chlorine bleaching of pulp and paper, for example, can result in small quantities of dioxins and furans [109]. The SCR systems for control of dioxins and furans were first used in the late 1990s in Europe and Japan [110] and have been employed in the U.S. at municipal waste incinerators.

Research has shown that commonly used metal oxide catalysts used in SCR for reducing NO<sub>x</sub> emissions (e.g., vanadium and tungsten oxides on a titanium or platinum oxide based substrate) from waste incineration systems can also reduce dioxin and furan emissions. This means SCR allows for an integrated approach to NO<sub>x</sub> and dioxin/furan control, since only one pollution control device is needed to reduce the emission levels of both pollutants. The catalytic oxidation has been shown to occur in a temperature range of about 240 °C to 330 °C. Dioxin/furan destruction efficiencies of 95 to 98% have been demonstrated [109].

The following references were added to the end of the chapter:

[109] Tzimas, E., and S.D. Peteves. “NO<sub>x</sub> and Dioxin Emissions from Waste Incineration Plants”, European Commission Joint Research Centre, EUR 20114 EN.

[110] Maaskant, Onno L. “The Shell System for NO<sub>x</sub> Removal and Dioxin Destruction from Incineration Flue Gas, Third Symposium on Incineration and Flue Gas Treatment Technologies, Brussels, July 2001.

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to the discussion of Retrofit Versus New Design and Balance of Plant in Section 2.2.6:

“Retrofit of SCR on an existing boiler or cement kiln has higher capital costs than SCR installed on a new system. There is a wide range of SCR retrofit costs due to site-specific factors, scope differences, and site congestion [10]. Specific factors that impact the retrofit costs for boilers include the following: [10]

- The amount of available space between and around the economizer and air heater;
- Congestion downstream of the air heater (i.e., buildings, conveyors, existing ESPs, FGD system, ID fan, or stack);
- The age/vintage and manufacturer of the boiler;
- The design margin of the existing ID fan (i.e., the need to upgrade or replace fan impellers, replace ID fans, or add booster fans);
- The capacity, condition, and design margins of the electrical distribution system;
- The design margins of the existing structural steel support systems;



- The positive and negative design pressure of the furnace and existing ESP; and
- The number, nature, and type of existing items that must be relocated to accommodate the SCR and associated systems.

While not all of these components are specifically applicable to cement applications, each of these problems have an equal counterpart for cement kiln retrofits. Additional equipment for catalyst cleaning and dust removal, including air compressors are necessary for cement systems.”

**Response:** The EPA agrees with the commenter that each retrofit issue discussed has a related counterpart for cement kilns as well. The discussion of catalyst cleaning for cement kilns is discussed elsewhere in the revised chapter (see section 2.2.5 subsection Soot Blower or Sonic Horn), as the additional cleaning equipment would be needed for both new and retrofit kilns. The revisions that have been implemented include the following:

“Retrofit of SCR on an existing unit has higher capital costs than SCR installed on a new-system. There is a wide range of SCR retrofit costs due to site-specific factors, scope differences, and site congestion [10]. Specific factors that impact the retrofit costs include the following: [10]

- The amount of available space between and around the economizer and air heater;
- Congestion downstream of the air heater (i.e., buildings, conveyors, existing ESPs, FGD system, ID fan, or stack);
- The age/vintage and manufacturer of the boiler;
- The design margin of the existing ID fan (i.e., the need to upgrade or replace fan impellers, replace ID fans, or add booster fans);
- The capacity, condition, and design margins of the electrical distribution system;
- The design margins of the existing structural steel support systems;
- The positive and negative design pressure of the furnace and existing ESP; and
- The number, nature, and type of existing items that must be relocated to accommodate the SCR and associated systems.

While not all of these components are specifically applicable to cement kilns, each of these issues have an equal counterpart for cement kiln retrofits.”

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to the discussion of Combustion Unit Design and Configuration in Section 2.2.6:

“Boiler size is one of the primary factors that determines the SCR system capital costs. In addition, boiler configuration influences SCR costs. Boiler configurations that split the flue gas flow for two or more air preheaters or particulate removal systems require more than one SCR reactor. Additional reactors substantially increase capital costs. Boiler operations that have varying operating load, frequent startups/shutdowns, or seasonal operations require an SCR bypass. Additional ductwork, dampers, and control systems increase the SCR system

capital costs. The SCR system may require modifications to draft fans and/or installation of additional fans. This increases both capital and operating costs of the SCR system. In addition, boiler and duct modifications may be required for implosion protection to accommodate increased draft requirements [53].

“In a cement application the kiln type, production rate, dust loading, the presence of catalyst poisons, and the magnitude and variability of raw material sulfur, SO<sub>2</sub>, and SO<sub>3</sub> are all important factors impacting capital and operating costs for SCR systems.”

**Response:** The EPA agrees that the characteristics mentioned by the commenter are important for all applications of SCR and has included the recommended revisions in the final revised chapter.

## 2.3 Design Parameters

**Commenter: Portland Cement Association**

**DCN: EPA-HQ-OAR-2015-0341-0023-A1**

**Comment:** The commenter recommended the following revisions to the first paragraph in Section 2.3:

“SCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required catalyst volume are not published in the technical literature [42]. Furthermore, the design is highly site-specific, especially in cement applications. In light of these complexities, SCR system design is generally undertaken by providing all of the plant- and boiler-specific data or kiln specific raw material and gas composition data to the SCR system supplier, who specifies the required catalyst volume and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling [33]. Because of the variability of the raw materials for cement kilns, it is highly recommended that a 6-12 month slip stream pilot study be conducted prior to design of the full scale SCR. The pilot study is intended to determine if the trace elements and dust characteristics are going to be compatible with the catalyst for long term performance. Even with pilot testing catalyst selection has proven to be a trial and error process for cement kilns. . . .

As noted in previous sections, cement plant SCR applications present industry and site specific design challenges that are substantially different than for utility boilers. Further, there are only a handful of cement SCR systems in existence and available design and cost information for those systems is very limited. Therefore, the Design Parameters, Cost Analysis and Cost Examples in the remainder of this document should not be utilized for cement kiln SCR design or cost estimation.”

**Response:** We agree with the commenter that site-specific operating and design characteristics must be taken into account when designing an SCR. In most cases, analyzing the flue gas and temperature profiles is sufficient to provide the necessary information for designing an SCR. For cement plants, we agree that information on the raw materials is useful since these materials can contain sulfur and ammonia. We also agree that pilot testing can be helpful to characterize the flue gas composition and ensure an appropriate catalyst is selected. However, we disagree that the design and cost equations would not be applicable to

cement plants. An SCR for a cement plant consists of the same basic equipment as would be required for a boiler. The operating procedures would also be the same. Hence, the capital and operating costs for an SCR on a cement kiln are expected to be similar to those estimated by the IPM for utility boilers. We have made the following revisions to Section 2.3:

“SCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required catalyst volume are not published in the technical literature [42]. Furthermore, the design is highly site-specific. In light of these complexities, SCR system design is generally undertaken by providing all of the plant- and unit-specific data to the SCR system supplier, who specifies the required catalyst volume and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling [33]. For some industrial applications, such as cement kilns where flue gas composition varies with the raw materials used, a slip stream pilot study can be conducted to determine whether trace elements and dust characteristics of the flue gas are compatible with the selected catalyst.”

#### **2.3.1 Boiler Heat Input**

No comments.

#### **2.3.2 Heat Rate Factor**

No comments.

#### **2.3.3 System Capacity Factor**

No comments.

#### **2.3.4 Uncontrolled NO<sub>x</sub> and Stack NO<sub>x</sub>**

No comments.

#### **2.3.5 NO<sub>x</sub> Removal Efficiency**

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 4-46, Section 2.3.5: Overall the outlet NO<sub>x</sub> and removal efficiency are also dependent on how many start-ups and shut-downs occur in the averaging period. During periods when the temperature is too low for the SCR to be effective (i.e., start-ups and shut-downs), NO<sub>x</sub> emissions could be a factor of 10 higher than during normal operation. The 0.05 lb/MMBtu may not be possible when start-ups and shut-downs are included. We suggest changing the calculations to account for start-ups and shut-downs.

**Response:** The EPA disagrees with the commenter that the SCR calculations should be altered to account for start-up and shut-down. The estimated operating time, for instance, is used to calculate estimated costs, such as estimated annual cost of reagent (and therefore effects on the NO<sub>x</sub> removal efficiency). Hence, to correct the estimated costs for start-up/shutdown periods when the temperature is too low for the reagent to be effective, the number of operating hours

during which reagent is not injected, which will have an effect on NO<sub>x</sub> removal efficiency, would be subtracted from the value of  $t_{op}$ . For most facilities, however, the Agency believes this adjustment would be small and have negligible impact on annual operating costs. In addition, the Agency has found that coal-fired EGUs burn fuels such as natural gas and number 2 fuel oil, fuels that generally cleaner than coal, during startup and prior to the start of electric generation. The use of these fuels is a normal part of coal-fired EGU operation. Also, this same study found that start-ups at coal-fired EGUs on average took 9 hours from the beginning of the event to when electricity began generating (Reference: U.S. EPA/OAR, “Assessment of Startup Period at Coal-Fired Electric Generating Units –Revised,” November 2014”, found at <https://www3.epa.gov/airtoxics/utility/matsssfinalrulesd110414.pdf>).

### **2.3.6 NO<sub>x</sub> Removal Rates**

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** Page 2-46, Section 2.3.6: The chapter must also account for start-ups and shut-downs, when the temperature is too low for the SCR to operate, in calculating annual NO<sub>x</sub>.

On page 2-72, the  $CF_{scr}$  factor should always be less than 1 due to start-ups and shut-downs, when the temperature is too low for the SCR to operate. The  $CF_{scr}$  equation should factor in the number and durations of start-ups and shut-downs and should be in hours rather than days.

**Response:** The EPA disagrees with the commenter that the  $CF_{SCR}$  should be adjusted for start-ups and shut-downs. The SCR capacity factor,  $CF_{SCR}$ , is simply the ratio of the theoretical number of days the SCR could operate to the total number of days per year (i.e., 365 days), as shown in Equation 2.9. This factor is used to account for SCRs that operate only during the ozone season. The total system capacity factor,  $CF_{total}$ , is the estimate of the fraction of time during which the SCR would be expected to operate and is calculated by multiplying the  $CF_{SCR}$  by the  $CF_{plant}$ , i.e., the ratio of the actual annual fuel burned to the maximum annual fuel that could be burned in the combustion unit, as shown in Equation 2.7. The total system capacity factor,  $CF_{total}$ , is then used to calculate the estimated SCR operating time,  $t_{op}$ , by multiplying  $CF_{total}$  by 8760 hours/year, as shown in Equation 2.59. The estimated operating time is used to calculate estimated costs, such as estimated annual cost of reagent. Hence, to correct the estimated costs for start-up/shutdown periods when the temperature is too low for the reagent to be effective, the number of operating hours during which reagent is not injected would be subtracted from the value of  $t_{op}$ . For most facilities, however, this adjustment would be small and have negligible impact on annual operating costs. In addition, the Agency has found that coal-fired EGUs burn fuels such as natural gas and number 2 fuel oil, fuels that generally cleaner than coal, during startup and prior to the start of electric generation. The use of these fuels is a normal part of coal-fired EGU operation. Also, this same study found that start-ups at coal-fired EGUs on average took 9 hours from the beginning of the event to when electricity began generating, a very short period of time compared to a year (Reference: U.S. EPA/OAR, “Assessment of Startup Period at Coal-Fired Electric Generating Units –Revised,” November 2014”, found at <https://www3.epa.gov/airtoxics/utility/matsssfinalrulesd110414.pdf>).

### **2.3.7 Actual Stoichiometric Ratios**

**Commenter:** Arizona Public Service Company (APS)

**DCN:** EPA-HQ-OAR-2015-0341-0028-A1

**Comment:** Page 2-47, Section 2.3.7: If “ASR = moles of equivalent NH<sub>3</sub> injected/moles of uncontrolled NO<sub>x</sub>,” then it should be the same for urea as ammonia. See page 1-34 of the SNCR section where ASR is defined as “moles of reagent” rather than “moles of equivalent NH<sub>3</sub>.”

**Response:** We agree with the commenter that the definition of ASR should have been based on the moles of reagent injected, not the moles of equivalent NH<sub>3</sub> injected. Upon further review of reference 56 we have also determined that the denominator in this term should be based on the moles of NO<sub>x</sub> removed instead of the moles of uncontrolled NO<sub>x</sub>. Specifically, reference 56 calculates the quantity of ammonia injected based on the amount of NO<sub>x</sub> removed multiplied by a factor of 1.05 moles of NH<sub>3</sub> injected per mole of NO<sub>x</sub> removed. The “extra” 5 percent is to account for the 2 moles of NH<sub>3</sub> that are needed to react with the small percentage of the NO<sub>x</sub> that is NO<sub>2</sub> and to account for a small amount of NH<sub>3</sub> slip, assuming the NO and NO<sub>2</sub> removal efficiencies are both equal to the overall NO<sub>x</sub> removal efficiency. Although reference 56 does not discuss the procedure for calculating the amount of urea that would be needed, it appears reasonable to conclude that the equation would be the same except that the factor would be 0.525 moles of urea injected per mole of NO<sub>x</sub> removed because 2 moles of NH<sub>3</sub> are released per mole of urea injected. This assumption is consistent with the procedure used to estimate the urea rate in the documentation for IPM version 5.13. The ratio between these two values (1.05/0.525) is consistent with the ratio of the actual stoichiometric ratios for ammonia and urea in the SNCR chapter. However, because the terms are defined differently (i.e., a different value in the denominator), we decided to coin a new name for this factor in the SCR chapter to avoid any future confusion between the two chapters. This factor is called the “Stoichiometric Ratio Factor (SRF)” in the revised SCR chapter. This factor is used in Equations 2.18, 2.21, and 2.35. We have also revised the discussion in Section 2.3.7 to read as follows and made a conforming change to the discussion of actual stoichiometric ratios in Section 2.2.2:

#### **“Stoichiometric Ratio Factor”**

“The stoichiometric ratio factor (SRF) indicates the actual amount of reagent needed to achieve the targeted NO<sub>x</sub> reduction. Typical SRF values are higher than theoretical values due to the complexity of the reactions involving the catalyst and limited mixing. Higher SRF values generally result in increased NO<sub>x</sub> reduction. The SRF is an important parameter in SCR system design because it establishes the reagent use of the SCR system. The SRF is defined as:

$$SRF = \frac{\text{moles of reagent injected}}{\text{moles of NO}_x \text{ removed}} \quad (2.13)$$

In a design developed by a system supplier, the SRF would be adjusted to account for temperature, residence time, degree of mixing, catalyst activity, and allowable ammonia slip for a specific boiler. No equation for estimating SRF is available for SCR. The value for SRF in a typical SCR system, using ammonia as reagent, is approximately 1.05 [33]. This value incorporates design margins for ammonia slip and the small amount of NO<sub>2</sub> in the boiler flue

gas, which requires two moles of  $\text{NH}_3$  per mole of  $\text{NO}_2$  instead of one mole of  $\text{NH}_3$  per mole of  $\text{NO}$  as shown in Equation 2.1a. For an SCR system using urea as the reagent, 0.525 is a typical value for SRF [8].

**Commenter:** Arizona Public Service Company (APS)

**DCN:** EPA-HQ-OAR-2015-0341-0028-A1

**Comment:** Page 2-47, Section 2.3.7: The preferred method to calculate actual ammonia usage would be to use the  $\text{NO}_x$  conversion rate, the 1.05  $\text{NO}_2/\text{NO}_x$  factor, and the allowed slip. Back-calculating from ASR is overly complicated and unnecessary. We suggest changing the calculation or including both methods.

**Response:** We disagree with the commenter that the calculation of reagent usage, shown in equation 2.35, is overly complicated. We note that equation 2.35 is preferred over the method suggested by the commenter since it calculates the amount of reagent input to the process. In the approach suggested by the commenter, the reagent usage would be estimated based on the amount of  $\text{NH}_3$  reacted with  $\text{NO}_x$  and the expected  $\text{NH}_3$  slip. As noted in section 2.2.6,  $\text{NH}_3$  will also react with sulfur trioxide in the flue gas stream to form ammonium bisulfate ( $\text{NH}_4\text{HSO}_4$ ) and ammonium sulfate ( $(\text{NH}_4)_2\text{SO}_4$ ). The approach suggested by the commenter may underestimate the amount of reagent injected.

### **2.3.8 Flue Gas Flow Rate**

No comments.

### **2.3.9 Space Velocity and Area Velocity**

No comments.

### **2.3.10 Theoretical $\text{NO}_x$ Removal Efficiency for $\text{NH}_3$ Slip Determination**

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** On page 2-50, the ammonia slip equation subtracts one dimensionless number from another to provide slip in ppm, which does not seem to be good science, and the reference cited is a product brochure, not a peer-reviewed scientific assessment.

**Response:** The original reference for Equation 2.20 should have been reference 56, not reference 36. According to this reference, the right hand side of the equation should be multiplied by the inlet  $\text{NO}_x$  level in ppmv. Upon further consideration, we have decided to remove Equation 2.20 from the final chapter because the efficiency term in the equation is based on the assumption that the number of moles of ammonia reacted equals the number of moles of  $\text{NO}_x$  removed. This assumption does not account for any  $\text{NO}_2$  reduction, and it does not account

for ammonia losses through other undesirable reactions. Additionally, using the inlet NO<sub>x</sub> level in ppmv is inconsistent with the use of inlet NO<sub>x</sub> levels in lb/MMBtu elsewhere in the chapter.

**Commenter:** Arizona Public Service Company (APS)

**DCN:** EPA-HQ-OAR-2015-0341-0028-A1

**Comment:** Page 2-50, Section 2.3.10: There seems to be some missing information in formula 2.20. We cannot determine how the product of two ratios translates to a ppm value.

**Response:** See the comment above for the response to the comment regarding equation 2.20.

### **2.3.11 Catalyst Volume**

No comments.

### **2.3.12 SCR Reactor Dimensions**

No comments.

### **2.3.13 Estimating Reagent Consumption and Tank Size**

No comments.

## **2.4 Cost Analysis**

### **2.4.1 Total Capital Investment**

#### ***Cost Year and Escalation to Future Years***

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** The cost equations indicate that the methodology was developed to estimate costs in 2012 dollars. The cost methodology should be updated to reflect the year in which the chapter revision will be finalized (e.g., 2015 or 2016).

**Response:** The EPA has historically provided the capital cost equations in the original dollar year of the data provided by the source, i.e., the base year. Users of the Cost Manual typically scale the costs from the base year to the current year (or most recent year with final cost indices data). It is true that EPA may conduct some normalizing when the original sources are from multiple years. Because the original S&L methodology included some scaling to cost year 2012, the EPA did not conduct any additional scaling. Users will simply scale from the base year of 2012 to the cost year of interest.

### ***Escalation to Future Year***

**Commenter:** Xcel Energy

**DCN:** EPA-HQ-OAR-2015-0341-0029-A2

**Comment:** EPA Should Include the Cost of Escalation Rather Than Use a 2012 Dollar Basis.

The SCR chapter does not identify inclusion of escalation in estimates for construction or operating and maintenance costs. The Section 1, Chapter 2 – Cost Estimation: Concepts and Methodology does identify a method for including escalation and suggests using the Vataavuk Air Pollution Control Cost Indexes. EPA discontinued support of this index in 2005 and suggested use of the Air Compliance Advisor software. The software references use of the Chemical Engineering Plant and Equipment Cost Indexes and has an internal adjustment of costs to an in-service year. The SCR chapter should reference use of the Chemical Engineering Indexes for adjustment of cost estimates to the current year.

In addition, the Chemical Engineering Indexes only report actual changes in costs for prior years. They do not project escalation for future years. The Manual should provide some method for projecting escalation from the year the estimate is developed until the project is placed in-service. In addition to providing accurate estimates of project costs at the time of installation, projecting escalation is needed as regulatory agencies (i.e., Public Utility Commissions “PUCs”) tend to focus on the initial estimates during their approval process for the installation of emission controls. The Manual should allow each project to justify and utilize a site-specific escalation approach for future years as agreed upon by the local regulatory agencies and the facility owner.

**Response:** For capital costs, the EPA agrees that a reference to use of the CE Cost Indices for estimating costs from a base cost year to the current cost year is appropriate, and the draft revised section included such a footnote to the CEPCI (see p. 2-54). This reference has been maintained in the final section.

Escalation of capital costs to a future in-service year is not consistent with the real basis (not nominal or inclusive of inflation) for the Cost Manual methodology. The Control Cost Manual methodology is laid out in Section 1, Chapter 2 of the Manual.

There is not a need to scale annual costs, and this has not been our historical convention. For operating costs, the appropriate inputs for the current cost year of interest should be used, i.e., current labor costs, reagent costs, utility cost, and catalyst replacement cost. The maintenance costs would already be scaled appropriately based on escalation of the capital costs to the appropriate cost year (i.e., maintenance costs are a percentage of TCI).

### ***Boiler Type and Size***

**Commenter:** American Petroleum Institute (API)

**DCN:** EPA-HQ-OAR-2015-0341-0020-A1

**Comment:** *Utility Coal-fired Boiler SCR Information is Unlikely to be Representative of SCR Installation on Oil- and Gas-fired Industrial Boilers.*



It is incorrect to apply cost data for coal-fired utility boilers to industrial boilers for the following reasons<sup>28</sup>:

- Industrial boilers are generally of much lower design firing than utility boilers, typically <100 MW equivalent versus mostly >100 MW for utility boilers and SCR costs per unit of firing are much higher for smaller units than for larger<sup>29</sup>. As a result, the scaling factor developed for larger coal fired equipment is unlikely to be applicable to oil- and gas-fired equipment. Nor is it clear, as discussed in Comment III.1.4 below, when the scaling factor only applies below certain firing rates.
- Industrial oil- and gas-fired boiler designs are more varied and of different layout than coal-fired utility boilers. This impacts construction difficulty, cost variability, SCR siting, etc. For instance, industrial boilers, typically being much smaller than utility boilers, are often one piece construction making it much harder to integrate an SCR into the exhaust gas path. Furthermore, Due to the nature of the flue gas path, package boilers (a common type of industrial boiler) do not have a suitable location in the proper temperature range to successfully install an ammonia injection grid (AIG) and catalyst. Industrial boilers may even be natural draft, thereby requiring significant revisions, stack replacement and/or installation of an ID fan to accommodate the SCR unit.
- Some industrial boilers fire both liquid and gaseous fuels. This can impact the SCR sizing, stack gas flows and characteristics, and the stack gas temperature profile.
- The heat configurations of industrial boilers are different than the heat configuration for utility boilers since industrial boilers are typically designed to produce lower pressure steam than do utility boilers and often, multiple levels of steam. This impacts the exhaust gas and catalyst temperature and residence time profiles and NO<sub>x</sub> conversion, the boiler revisions needed for the SCR takeoff and return, the amount of catalyst required, and the value of lost steam production due to reduced secondary heat recovery.
- Oil- and gas-fired boilers have different burner characteristics and configurations than do coal-fired utility boilers and lower stack gas NO<sub>x</sub> concentrations, so other NO<sub>x</sub> controls, such as low-NO<sub>x</sub> burners, can reduce NO<sub>x</sub> emissions to low levels without use of SCR. Lower NO<sub>x</sub> concentrations entering an SCR unit, impacts reaction characteristics and impacts catalyst quantity and temperature needs.
- Industrial boilers operate at varying loads compared to utility boilers, making it more difficult to maintain SCR catalyst temperature in the ideal range and leading to lower

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<sup>28</sup> On page 33517 of the Notice of Data Availability EPA requests comment on how the costs of SCR installation and operation differ between the electric power sector and industrial sources. This list of differences addresses that question.

<sup>29</sup> For instance, Robert Peltier reports in the ePower blog (Air Quality Compliance: Latest Costs for SO<sub>2</sub> and NO<sub>x</sub> Removal (effective coal clean-up has a higher—but known—price tag., June 13, 2009) “The cost of construction labor on smaller projects exceeds the average construction labor cost in all categories by about 50%. The implication is that small plants will be cost penalized by their lack of economies of scale because they may be more difficult to retrofit” and “economies of scale also impact SCR material costs, with larger units costing less to retrofit, on a \$/kW basis, than smaller units.”

average overall NO<sub>x</sub> removals and/or larger catalyst beds (to offset lower conversions due to lower temperatures).

- The layout of industrial sites is often very compact, requiring a complex and labor-intensive design, and less than optimum construction approaches. Industrial boilers are also often located in areas adjoining process equipment, imposing additional costs to minimize safety risks, locate cranes and manage construction materials.

For all of these reasons, it is unreasonable to expect that cost data for coal fired utility boilers is transferrable to industrial oil- and gas-fired boilers and thus the draft equations for oil- and gas-fired boilers should not be finalized.

**Response:** While the commenter indicates that the coal-fired cost equations from IPM should not be applied to industrial oil- and gas-fired units, the EPA has not suggested that coal-fired equations be applied to oil and gas units. Scaling factors for oil and gas-fired boilers are found section 5.2.4 of the IPM documentation, which is applicable for units with a capacity of 25 MW or greater, and these scaling factors are not part of the equations developed by Sargent & Lundy. For the industrial sector, the user can calculate costs using MMBtu/hr instead of MW with the appropriate conversion factor.

All the comments referring to size, variable load, unique configuration / site layout issues, different sizes, insufficient space for retrofit of SCR, temperature profile, insufficient temperature, etc., were voiced by the EGU sector in the past regarding SCR retrofits. Despite of the concerns for inability to place an SCR on an existing system, engineers were able to design a solutions which enabled SCR to be installed at many EGUs. The agency believes sufficient engineering talent exists for the non-EGU sector and will enable this sector to retrofit with an SCR, if they choose to select this method for reducing NO<sub>x</sub> emissions.

The agency agrees firing gas or liquid fuels has an influence on SCR size. Engineers will design the system to accommodate either fuel. For instance, the coal fired EGU sector while burning solid fuel coal, start units with gas or oil – engineers were able to design an SCR for these systems. Some CTs (combustion turbines) are dual fuel fired (gas and oil) and are equipped with SCRs.

Catalyst activity versus temperature is an important issue in designing catalytic reactors. For example, in the EGU sector, combustion turbine operators face temperatures that are too high; while the coal-fired EGUs face temperatures that are too low. In both cases, engineers have designed SCR systems to enable compliance with regulations.

The Agency recognizes that by lowering the amount of NO<sub>x</sub> discharged from the furnace (with Low NO<sub>x</sub> burner combustion control technology), the loading to the SCR will be reduced and consequently reduces the size of the needed SCR.

The ideal or optimal temperature for an SCR is a single operating temperature, though it is much more typical for SCRs to operate in an optimal temperature range. Catalyst selection must account for the operating temperature range and retrofit design features allow the temperature range to be extended.

At low loads (e.g., low firing rates) – the unit discharged less overall NO<sub>x</sub> due to the lower temperatures within the combustion zone.

An important point regarding oil and gas-fired units is that the combustion gas stream exiting an oil or gas fired boiler is significantly cleaner (eg. no ash,) than coal-fired units; consequently, units firing these cleaner fuels require smaller catalyst beds and can install smaller SCR reactors than coal-fired units having the same equivalent inlet NO<sub>x</sub> concentration.

While the commenter notes size as a concern, the final section would only cover units, either utility or industrial, that are greater than the threshold value of 25 MW or roughly 250 MMBtu/hr. The EPA agrees that other NO<sub>x</sub> techniques besides SCR may also be available for reducing NO<sub>x</sub> emissions from industrial boilers.

**Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.**

**DCN: EPA-HQ-OAR-2015-0341-0022-A1**

**Comment:** [Utility vs. Industrial] Page 2-60 states that the use of the utility equations may overestimate the costs for industrial boilers since utility boilers are likely more complex than industrial boilers. However, since industrial boilers are much smaller, they do not benefit from economies of scale. Most industrial boilers are also located in tight spaces within a plant site, and retrofits can be very difficult. The costs provided need to properly account for these offsetting factors for industrial boilers. Another consideration is that some costs associated with an SCR installation do not vary with the size of the unit. For example, the cost for the controls and instrumentation (including NO<sub>x</sub> and ammonia analyzers) are essentially the same for both large and small units, so they represent a larger fraction of the total cost of an installation on a smaller unit and should not be ignored.

**Response:** While the commenter mentions that industrial boilers are much smaller than utility boilers, it is important to note that the costing methodology is only applicable to larger industrial boilers that are comparable in size to utility boilers. Units of similar heat input size, whether used for industrial or utility purposes, are expected to have roughly the same TCI.

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** There should not be an appreciable difference in the capital costs between utility and industrial SCRs; however, the operations and maintenance cost can be different due to differences in the start-up/shut-down cycles. It is possible that, industrial boilers might run steadier since they are only handling their own load. Utility boiler operation is subject to customer demand and thus could cycle more frequently. Also, power costs for utility SCR might be higher. This may seem counter-intuitive, but the industrial boiler will likely provide the power to its SCR. For the utility SCR, power would actually be indirectly supplied from the next run unit or the power market, typically at a higher cost than the unit with the SCR would provide it.

**Response:** We agree with the commenter that appreciable differences in capital costs between utility and industrial SCRs should not occur, but that operating and maintenance costs could certainly differ. Power costs for operation of utility and industrial SCRs could certainly differ.

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Page 2-55 states that the capital cost equations are applicable to utility boilers with full-load capacities greater than or equal to 25 MW and that equations are also provided for industrial boilers with heat input capacities greater than about 250 MMBtu/hr. This is generally consistent with the cost equations in Section 2.4.1.3, which state that they are applicable to units greater than 205-275 MMBtu/hr (depending on the calculation). However, industrial units of this size represent a small fraction of the total population of industrial fired equipment. This is a significant gap in the usefulness of this chapter of the Cost Control Manual.

**Response:** The commenter notes that the boiler size covered under the revised section represents a small number of industrial boilers in the U.S., and the EPA agrees that the adopted cost equations are only appropriate for these specified size ranges. The distribution of boiler sizes is supported by an inventory of boilers in the U.S. compiled by Energy and Environmental Analysis, Inc., in 2005. The inventory shows that there were approximately 19,500 industrial boilers larger than 10 MMBtu/hr, and approximately 1,300 of those were larger than 250 MMBtu/hr. Overall, the size of the average industrial boiler was 36 MMBtu/hr (p. ES-1). The costing approach adopted from Sargent & Lundy covers larger boiler sizes only, and costs for smaller boilers cannot be estimated using this approach. (Energy and Environmental Analysis, Inc., "Characterization of the U.S. Industrial/Commercial Boiler Population". May 2005. [http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/characterization\\_industrial\\_commercial\\_boiler\\_population.pdf](http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/characterization_industrial_commercial_boiler_population.pdf))

### *Scaling Factors vs. Linear Costs*

**Commenter:** American Petroleum Institute (API)

**DCN:** EPA-HQ-OAR-2015-0341-0020-A1

**Comment:** *The Extension of the Cost Curves to Units of <100 MWs Has Not Been Justified and Is Questionable.*

In the IPM SCR cost methodology report it is indicated that the cost information curves developed for coal-fired boilers are not as accurate below 100 MW as they are above 100 MW. Sargent and Lundy state:

The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. The older units which comprise a large proportion of the plants in this range generally have more compact sites with very short flue gas ducts running from the boiler house to the chimney. Because of the limited space, the SCR reactor and new duct work can be expensive to design and install. Additionally, the plants might not

have enough margins in the fans to overcome the pressure drop due to the duct work configuration and SCR reactor and therefore new fans may be required.

Thus, the extension of the utility oil and gas-fired boiler cost curves to 25 to 100 MW industrial units, which represents the vast majority of such units, is highly questionable. If equations for industrial boilers are included in the final drafts, API recommends the applicability range be limited to industrial boilers equivalent to greater than 100 MW rather than 25 MW.

**Response:** The SCR equations prepared by Sargent & Lundy apply only to coal-fired units. EPA uses the equations for oil & gas units from IPM v.5.13 (section 5.2.4 for documentation), and these equations are found at [https://www.epa.gov/sites/production/files/2015-07/documents/chapter\\_5\\_emission\\_control\\_technologies\\_0.pdf](https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_emission_control_technologies_0.pdf). The Agency converted the IPM equations from MW to MMBtu/hr for the industrial sectors (which is the format for defining equipment size). The dimensionless nature of the equations was preserved through proper use of conversion factors.

The cost equations for boilers fired with oil or gas include a scaling factor, or power rule, for all units up to 500 MW or equivalent (i.e., 5,500 MMBtu/hr), see Equations 2.45 and 2.52 of the final chapter. This scaling factor does appropriately scale the capital costs for units less than 1,000 MMBtu/hr (or 100 MW), such that smaller units in the 275 MMBtu/hr range have a larger multiplier than units in the 1,000 MMBtu/hr range. For example, a 275 MMBtu/hr unit would include the term  $(2,200/275)^{0.35}$ , resulting in multiplication by a factor of 2.07. For a 1,000 MMBtu/hr unit, the equation would include the term  $(2,200/1,000)^{0.35}$ , resulting in multiplication by a factor of 1.32. Thus, the cost equations for industrial boilers do incorporate appropriate scaling of capital costs for smaller units down to 275 MMBTU/hr capacity.

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment: *The Lack of Scaling Factors in Equations 2-54 and 55 for Should Be Justified.***

Equations 2-54 and 2-55 are recommended to estimate the cost for retrofitting SCR on oil-fired industrial boilers >5,500 MMBTU/hr and gas-fired industrial boilers >4,100 MMBTU/hr, respectively. In these equations a cost factor in \$/MMBTU/hr is multiplied by the boiler design firing in MMBTU/hr. Yet, in equations 2-52 and 53, which apply to these same units with <5,500 and 4,100 MMBTU/hr capacity, a scaling factor is included since cost is not directly related to design firing (i.e., the relationship between cost and size is not linear.) No explanation is provided in the [IPM] documentation or in these draft Chapters why the cost/design relationship suddenly becomes linear above these capacities or why these particular capacities were selected for this sudden change. It is worth noting that no such break is suggested for industrial coal-fired boilers.

API recommends EPA explain the basis for these two equations, justify the linear relationship they use, and explain why the relationship between SCR cost and boiler capacity changes at these particular points.

**Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.**

**DCN: EPA-HQ-OAR-2015-0341-0022-A1**

**Comment:** The different minimum sizes used for the thresholds for various categories on page 2-62 are confusing. On this one page,  $\geq 250$  MMBtu/hr is used for balance of plant costs (BPC);  $\geq 275$  MMBtu/hr is used for Industrial, oil-fired units; and  $\geq 205$  MMBtu/hr is used for industrial, gas-fired units. The range of unit sizes over which the costs are supposedly linear (e.g., 275-5500 MMBtu/hr) is excessive and does not recognize economies of scale. Also, while the cost on a \$/MMBtu basis is significantly higher for smaller boilers, no cost estimation method has been provided for units that fall below the ranges specified.

**Response:** The Agency makes the following points in our response: first, the equations are not linear representations (they do not have the form  $y = mx + b$ ); they are non-linear equations (curves) and hence use an exponential power factor. Secondly, common mathematical practices accept halting calculations at the upper limit (and lower limit) rather than extrapolate a non-linear equation into an unknown region, which is a practice that is inappropriate. The value obtained at the limits is taken going forward (or backwards) to obtain a reasonable result. Thirdly, the presence of an exponential factor serves as a “scaling factor” for different sized units. As an example, for the range of 275 to 5,500 MMBtu/hr, the equation for this size range actually does include a scaling factor for the heat rate of the unit, so these costs are not linear. The EPA would like to note that for the equations for units  $> 5,500$  MMBtu/hr and  $> 4,100$  MMBtu/hr, no scaling factor is applied and the costs are assumed to be linear for this size range. Fourthly, at the time of the writing, EPA was unable to identify few if any oil / gas fired steam units with a capacity greater than 500 MW.

The Control Cost Manual SCR chapter adopts the utility oil and gas equations, and applies them to industrial oil and gas-fired boilers of the same sizes. While the commenter notes that the equations are linear for 275 to 5,500, the equation actually includes a scaling factor for the heat rate of the unit, so these costs are not linear. For the equations for units  $> 5,500$  MMBtu/hr and  $> 4,100$  MMBtu/hr, these equations have no scaling factor and in fact do appear to assume linear costs.

For the utility equations from IPM, there are no cost data available for smaller units that fall below the 25 MW threshold or equivalent heat input. Each of the threshold values in MMBtu/hr for coal, oil, and gas units are based on the net plant heat rate, or NPHR, which is 10,000 Btu/kWh for coal, 11,000 Btu/kWh for oil, and 8,200 Btu/kWh for natural gas. The original IPM equation scales are based on a 200 MW rating; to convert to a heat rate basis in MMBtu/hr for industrial boilers, the 200 MW was converted to a heat rate. The NPHR value appropriate for each fuel type was used to convert the IPM equation thresholds that used Megawatts to an equivalent heat rate basis in MMBtu/hr. Because the NPHR values are different for each fuel type, the heat rate threshold values are slightly different for the same MWh value. For example, the range for utility oil-fired units of 25 to 550 MW converts to 275 to 5,500 MMBtu/hr for industrial oil-fired units using an NPHR of 11,000 Btu/kWh. As a second example, the range for utility gas-fired units of 25 to 550 MW converts to 205 to 4,100 MMBtu/hr using an NPHR of 8,200 Btu/kWh for industrial gas-fired units.

***IPM Model Out of Date, Not Transparent, Develop New Model Based on Engineering Principles***

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** EPA's capital cost estimating methodology relies on outdated or poorly suited sources. The vast majority of sources that the Agency cites reflect SCR installations designed in 2004 or earlier. Similarly, the Integrated Planning Model ("IPM") cost estimation methodology that EPA relies on cites three sources: two of these are poorly suited for predicting the capital costs of modern and future SCR installations, while the third is based on proprietary data, preventing commenters from assessing its adequacy.

As a result of these flaws, unsurprisingly, the SCR capital cost methodology in the Draft SCR Chapter is a poor predictor of recent and future SCR capital costs. UARG's consultant compared estimates derived using EPA's methodology to known or currently projected capital costs of SCR installations at 17 electric generating units in 2011 or later. The EPA methodology contained in the Draft SCR Chapter significantly underestimated the capital costs of these projects, yielding cost estimates that were \$80-110/kW lower than the mean value of actual capital costs. These substantial errors suggest that EPA should reevaluate the IPM methodology presented in its Draft SCR Chapter. At the very least, the Agency should adopt a "reasonable estimate of contingency" for SCR retrofit installations of \$80-110/kW. Alternatively, on a percentage basis, EPA should adopt a contingency of 30-50 percent of capital cost predicted using the IPM methodology in the Draft SCR Chapter.

**Response:** The Agency notes that the S&L dataset, while proprietary and not open for public review, contains a majority of projects from the 2007 to 2012 timeframe and do represent recent capital costs for SCR installation.

Plant site elevation issues may play a role in the higher costs witnessed by the commenter; the S&L documentation (p.2 of that memo) within IPM discusses additional costs for plants at higher elevations. The SCR cost approach in the Cost Manual now contain a formula for estimating the elevation factor and elevation factor is included in the capital cost estimates. Additionally, the S&L equations are based on multiple lump-sum fixed price contract awards by the owner; they assume the owner manages the entire project. The reasons for higher costs witnessed by the commenter are most likely due to projects executed under an engineering, procurement, and construction (EPC) contract vehicle (also called design-build). Under these circumstances, the owner becomes a "client" and the contractor assumes all risk and responsibility. Please see p.3 of the IPM documentation at [https://www.epa.gov/sites/production/files/2015-08/documents/attachment\\_5-3\\_scr\\_cost\\_methodology.pdf](https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-3_scr_cost_methodology.pdf) for more information.

The data set for UARG includes cost estimates for approximately 14 SCR units from 2008 to 2010; approximately 15 SCR units from 2003 to 2004; and approximately 5 units that were constructed prior to 2000. Roughly 40 percent of the units are from 2008 to 2010 timeframe.

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** Section 5 compares EPA-projected capital cost with that observed in practice and critiques operating cost, as solicited by EPA.

The data provide important insights. First, the EPA cost correlation – absent owner’s costs and AFUDC – is almost identical to the correlation derived by UARG for units that came into commercial service from 2008 to 2011. The cost correlation curves should be kept in context – it is important to note that individual unit cost data vary significantly around the curve shown in Figure 5-1.

EPA’s predicted SCR capital cost is almost without exception well below actual capital cost incurred or derived for post-2011 SCR units. Of the 17 post-2011 units, there are four with incurred cost within 10% of the EPA projection; the cost for the 12 other units exceeds EPA’s estimate by at least 10%. Only one of the post-2011 SCR installations – a 1300 MW unit located in the Midwest - incurred a cost less than EPA’s projection. It may be concluded, therefore, that EPA’s estimating procedure is a lagging and not a leading indicator of SCR costs.

**Response:** Plant site elevation issues may play a role in the higher costs witnessed by the commenter; the S&L documentation (p.2 of that memo) within IPM discusses additional costs for plants at higher elevations. The SCR cost approach in the Cost Manual now contain a formula for estimating the elevation factor and elevation factor is included in the capital cost estimates. Additionally, the S&L equations are based on multiple lump-sum fixed price contract awards by the owner; they assume the owner manages the entire project. The reasons for higher costs witnessed by the commenter are most likely due to projects executed under an engineering, procurement, and construction (EPC) contract vehicle (also called design-build). Under these circumstances, the owner becomes a “client” and the contractor assumes all risk and responsibility. Please see p.3 of the IPM documentation at [https://www.epa.gov/sites/production/files/2015-08/documents/attachment\\_5-3\\_scr\\_cost\\_methodology.pdf](https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-3_scr_cost_methodology.pdf) for more information.

In project management, a contingency factor is part of a seller’s price for fixed price / lump sum contracts to cover monetary risks for unknowns. Depending on the seller’s expertise and client’s unknowns, this factor can have a broad range. The data used to create these cost estimating tools incorporates contingency factors (in this case, project and process contingency) charged by the suppliers of lump sum contracts, and the Agency consider these factors in total to be consistent to 10-15% of the total project cost. To then add a contingency factor to these cost estimating tools would lead to double counting.

However, to address the issues related to retrofit cost increases and to assist users in estimating costs due to SCR retrofits and new SCR installations, a retrofit factor, which will account for the



effect of retrofit difficulty on costs and new installation costs, has been developed and incorporated into the capital cost equations.

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)  
DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** Most references cited by EPA in a discussion of SCR capital cost are at least a decade old. Table 2-1a cites cost data for 155 units, with 132 representing units with SCR equipment designed in 2004 or preceding years, and 23 representing units designed in 2006 and later.<sup>30</sup> These outdated references are inadequate to serve as the basis for EPA's SCR capital cost estimates.

The IPM documentation references three data sources. Two of the sources are identified and available in the public domain and thus are subject to critical review. The third source is proprietary data that cannot be reviewed; as a result the impact of this proprietary data on the outcome is uncertain.

Specifically, the IPM model documentation cites the following major sources:

- Analysis of MOG and LADCO's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emissions Controls.<sup>31</sup> The reported costs in this document are based on (a) surveys in 2003 and 2004, (b) a single cost data point in 2006, and (c) a total of 70 installations reflecting world-wide application. Most data reflect SCR cost incurred prior to 2004. Item (c) reports numerous cost data but these focus on early SCR applications in Europe. The early European cost data are of limited applicability to U.S. sites for numerous reasons, perhaps most important the predominance of tower design boilers which enable better access for reactor location and construction equipment.

For these reasons, this reference is outdated and inappropriate for the purpose of establishing SCR cost for future applications.

- Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies.<sup>32</sup> This analysis, issued by UARG in 2010, reports SCR capital cost over several discrete periods, showing how cost escalated over time. Four timeframes are considered: (a) pre-2000, (b) 2000-2002, (c) 2003-2004, and (d) 2008-2010. (No cost data were available for units that started operation in 2005 through 2007). Figure 6-1 of the reference shows the cost incurred for the 2008-2010 installations significantly exceeds the cost incurred in prior years. This reference shows how SCR capital cost has escalated from early applications, and attempts to quantify the annual rate of cost increase.

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<sup>30</sup> Draft SCR Chapter 2, Table 2.1.a. The sum of the number of units cited in References [9] through [13] is at least 132, all referenced to the year 2004.

<sup>31</sup> Prepared for the Midwest Ozone Group, by J. Marchetti and J. Edward Cichanowicz, January 19, 2007. 16

<sup>32</sup> 2010 UARG Cost Report.

- Sargent & Lundy (S&L) Proprietary In-House Data. A third source for IPM is S&L proprietary data. Specifically, the IPM documentation notes the following:<sup>33</sup>
  - The published data were significantly augmented by S&L’s in-house database of recent projects
  - Additional proprietary S&L in-house data from 2007-2012 were included to confirm the index validity
  - Finally, the cost estimation tool was benchmarked against recent SCR projects to confirm the applicability to the current market conditions.

It is unclear how S&L’s proprietary data are used in the EPA correlation, or how the data was “benchmarked” against recent SCR projects. As a result, there is no basis to appraise how well the proprietary data corroborate or improve IPM.

In summary, IPM as used by EPA to project SCR capital cost – although representing a significant improvement over past efforts – is biased toward legacy data that may not be relevant to existing and future SCR candidates. Further, it is not clear how much the cost estimates derived from EPA’s procedure are influenced by proprietary data that cannot be reviewed.

**Response:** The accuracy, as desired by the commenter, encroaches upon a “level of effort” detailed proposal (as the A/E industry defines), which often requires hundreds of man-hours to complete. The S&L cost estimating tools were designed to provide budgetary- or study-level, estimates to assist the user in examining multiple different technologies for compliance options. They are not designed to establish a definitive price expectation for awarding contracts. To avoid the legacy, old information bias, CoST applies the Chemical Engineering Plant Cost Index (CEPCI) cost index, a well-established index to adjust costs between different years,, which suffices for the level of accuracy obtained in these estimating tools.

While the commenter notes that the costs in Table 2.1a are outdated and inadequate to serve as the basis for the SCR capital costs, these units and costs are not the basis of the capital cost estimates in section 2.4 of the SCR chapter. Table 2.1a was intended to provide example capital costs for past SCR projects and to show the range and types of units that have installed SCR over time. While some may be older units, the cost year is clearly identified in the table. The capital costs shown in Tables 2.1a and 2.1b are not part of the TCI estimates and do not serve as the basis of section 2.4.

The S&L dataset, while proprietary and not open for public review, contains a majority of projects from the 2007 to 2012 timeframe and do represent recent capital costs for SCR installation

The data set for UARG includes cost estimates for approximately 14 SCR units from 2008 to 2010; approximately 15 SCR units from 2003 to 2004; and approximately 5 units that were constructed prior to 2000. Roughly 40 percent of the units are from 2008 to 2010 timeframe.

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<sup>33</sup> IPM 2013 SCR Cost Report, page 1.

**Commenter: Sierra Club and National Parks Conservation Association**

**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** We recommend that the IPM model not be formally adopted for estimating SCR cost effectiveness. The IPM model is a good interim tool, as there is currently no other publically available method to independently estimate SCR cost effectiveness. Thus, it fills an important information gap. However, it has the following limitations that require that it be replaced with a more flexible model:

First, this model is a black box, developed using Sargent & Lundy's internal confidential SCR cost database. The bases of the regression equations are hidden from view. The underlying data and methods used to develop the regression equations that EPA is relying on have not been subject to review by the public. The EPA should make the underlying data available so that the public can independently evaluate it.

Second, the regression equations are simply a snapshot in time. The SCR chapter does not present any method for periodically reviewing and updating the regression equations, which are opaque and cannot be adjusted for advances in SCR technology or changes in catalyst formulations. For example, although we are unable to verify this without the underlying data, we believe it is unlikely that the S&L IPM model includes any of the cost savings that have more recently been afforded through catalyst refurbishing (rather than replacement), new catalyst formulations, and urea to ammonia on demand systems, which can significantly reduce operating and maintenance costs. The former is of particular concern given the significant, unexplained increases in catalyst replacement costs as estimated by the IPM model versus the previous CCM methodology.<sup>34</sup> The EPA should propose a procedure to assure the IPM model is updated periodically, at least every five years, and this procedure should be formally incorporated into the CCM. The procedure should require any proposed revisions to be subject to public review and comment.

Third, the IPM model was developed for the collection of SCRs in Sargent & Lundy's database. Thus, it includes both retrofits of varying complexity and new SCR installations. While it includes a "retrofit factor" to address this, a retrofit factor of 1, used in most analyses, corresponds to average retrofit difficulty. This significantly overestimates costs for a SCR on new units, which have no retrofit issues and incorporate the latest technology updates. Finally, the SCR chapter proposes to extrapolate the use of the IPM beyond its intended purposes, to industrial boilers and other sources.<sup>15</sup> The IPM was developed using regression methods specifically for coal-fired boilers, which have unique flue gas composition, and layout constraints. Thus, the IPM SCR model should not be extrapolated beyond coal-fired boilers. We believe these limitations can be addressed by identifying them and recommending solutions in the CCM as an interim step, while a model based on fundamental engineering principles is developed. The SCR chapter should be modified to include or refer to the actual data upon which the IPM algorithms rely. While we realize much of this data may be confidential, it is

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<sup>34</sup> See Proposal at pp. 2-76, 2-77, 2-84. The IPM-estimated annual catalyst replacement cost is roughly 3 times higher than the previous CCM methodology in each example. Given the lack of opportunity to review the data underlying the IPM catalyst replacement cost methodology, we support retaining the existing CCM approach. <sup>15</sup> Proposal at p. 2-43.

possible to scrub it so that owner and vendor information is assigned codes. Further, estimates made using the IPM regression-based equations should be supplemented with site-specific plant and vendor data, available from the applicant, and informed by agency site visits to determine reasonable retrofit factors. The IPM model should only be adopted as an interim method to estimate SCR cost effectiveness, while a more accurate, uniform, and transparent cost model, based on fundamental engineering principles, is developed.

**Response:** It is true that the data set used to develop the cost calculations includes both SCR retrofits and new installations. As we noted in the SCR chapter, the IPM likely overestimates costs for new units since the majority of the projects used in the IPM were SCR retrofits. To address the differences for new and retrofit units, we added a retrofit factor (RF) to each TCI equation that enables the TCI to be adjusted based on the level of difficulty of a retrofit project. A retrofit factor of 1.0 is used for retrofits of average difficulty. A retrofit factor of 0.8 for new construction, which reflects 20-30% lower costs of capital relative to an average retrofit cost estimate. This value is consistent with information supplied by other commenters and in the 2010 memorandum from Sargent & Lundy to US EPA on SCR costs, an earlier version of the 2013 Sargent & Lundy cost memo that is referenced in the Cost Manual chapter.

Unfortunately, we are not aware of an available cost data set for developing a separate cost model based solely on engineering principles.

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** The Proposed Cost Factor (\$80/kW) for Installing SCR on Industrial Oil- and Gas-fired Boilers Have Not Been Justified.

Section 2.4.1.3 of draft Chapter 2 proposes methods for calculating the TCI for installing SCR units on oil-fired boilers of 275 – 5500 and >5500 MMBTU/hr design firing and for gas-fired boilers of 205 – 4100 and >4100 MMBTU/hr design firing. The equations are all of the same form, setting forth a factor in \$/MMBTU which is multiplied by the ratio of a set firing rate to the boiler design firing, a scaling factor and an elevation factor. The elevation factor adjusts for the impact of lower atmospheric pressure on stack gas volume and thus equipment sizing. API has no comments on that factor.

It is explained in the draft that the \$/MMBTU factors are derived by converting the \$80/kW factor used for utility oil- and gas-fired boilers to \$/MMBTU.

On page 2-59 of draft Chapter 2, EPA indicates that \$80/kW is the “installed cost of an SCR system in 2012\$ for a 200 MW [utility] oil- or gas-fired boiler.” The explanation for the source of the \$80/kW and the associated scaling factors is given in Section 2.4.1 on page 2-56, where it is stated:

Total capital investment (TCI) includes direct and indirect costs associated with purchasing and installing SCR equipment. Costs include the equipment cost for the SCR system itself, the cost of auxiliary equipment, direct and indirect installation costs, additional costs due to installation such as asbestos removal, costs for buildings and site preparation, offsite facilities,

land, and working capital. In general, SCR does not require buildings, site preparation, offsite facilities, land, and working capital. A more detailed discussion of capital costs can be found in Section 1, Chapter 2 of this Manual. The total project cost or TCI for the SCR is based on the approach used by EPA CAMD in the Integrated Planning Model [8], and this approach includes both the direct capital costs and the indirect capital costs. The methods presented in sections 2.4.1.1 and 2.4.1.2 for utility boilers are identical to the methods in v5.13 of the IPM, except that two elements have been excluded, as noted above. The IPM does not include methods for estimating impacts to industrial boilers. Thus, the methods presented in sections 2.4.1.3 and 2.4.1.4 for industrial boilers are based on modified IPM equations; the equations were modified by replacing electricity production ratings with the corresponding typical boiler heat input capacities, as calculated using typical NPHRs, and assuming that SCR costs for industrial boilers and utility boilers that have the same heat input capacity would be the same.

The “IPM” referenced by EPA is the Integrated Planning Model for the electrical power industry, version 5.13<sup>35</sup>. This model is extremely specific to the electrical power industry, essentially modelling every unit in the US based on detailed knowledge of its feed and demand situation, its specific configuration, and detailed regulatory and consent decree situation. The methodology used for derivation of the \$/kW capital cost and the scaling factors for utility boilers is reported in Section 5.2.4 of Chapter 5 of the IPM Version 5.13 documentation<sup>36</sup>. No specifics of how the cost equations were developed or the data underlying them is provided, however. In Section 5.2.4<sup>37</sup> of that document, Sargent and Lundy do provide a general explanation, stating that they gathered published data and their own in-house data on the cost of SCR installations in the utility industry as the basis for developing the cost equations. The collected data was converted to 2012 dollars and grouped by coal type, NO<sub>x</sub> reduction efficiency and air pre-heater requirements. The data were refined by fitting each data set with a least squares curve to obtain an average \$/kW project cost as a function of unit size. Based on this report, all of the cost information used by Sargent and Lundy was for coal-fired utility boilers. No information is provided on how that coal boiler information was converted to curves for oil- or gas-fired utility boilers.

As in the IPM documentation, draft Chapter 2 is silent on how the TCI cost estimating equations for coal-fired utility boilers were converted to the equations presented for oil- and gas-fired utility boilers, which were then also applied to oil- and gas-fired industrial boilers. Furthermore, the TCI equations for utility boilers in draft Chapter 2 include, as separate terms, the SCR cost, reagent preparation costs (RPC), air preheater costs (APC), and balance of the plant costs (BPC) and a multiplier of 1.3 to reflect certain indirect costs, as discussed in Comment II.3 above (see equations 2.40 and 2.47 of the draft Chapter 2). Yet, the equations presented for oil- and gas-fired boilers (both utility and industrial) seem to only estimate the SCR cost (presumably including the RPC costs) and do not specifically include the indirect cost factor or the BPC cost. Since there is no detailed explanation of these equations or the \$80/kW factor,

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<sup>35</sup> Version 5.13 is no longer the latest IPM Version, however, the IPM 5.13 information is available at <http://www.epa.gov/airmarkets/programs/ipm/psmodel.html>.

<sup>36</sup> See EPA’s *Power Sector Modeling Platform v.5.13, Documentation for v.5.13, Chapter 5: Emission Control Technologies*, at <http://www.epa.gov/airmarkets/programs/ipm/psmodel.html>.

<sup>37</sup> Op. Cit., page 1.

it is not possible to tell if all required cost components were included for oil- and gas-fired industrial boilers. Of particular concern is whether BPC costs, which includes incremental induced draft (ID) fan capacity (or installation of an ID fan for natural draft boilers), has been included in the \$80/kW figure. Incremental ID capacity, and possibly conversion from natural draft to induced draft, is a distinct possibility for industrial boilers and represents a potentially very significant cost.

For an SCR cost estimate to be complete it must include all of these costs as well as the direct costs of the SCR system itself. Clearly, an SCR installation must include all of the facilities required to receive, store and supply reagent (RPC), to assure the boiler heat balance is as unaffected as possible (APC), to provide underground, site and infrastructure costs (BPC) and to provide the services required to install the project, such as detailed engineering and project management (indirect costs). It is unclear these costs or the costs for the required monitors (see Comment II.3) have been included in the \$80/kW cost factor.

TCI equations 2-52 and 2-53 also contain a scaling factor, since the \$80/kW is based on a utility boiler of 200 MW. However, no information is provided on how the scaling factor exponent of 0.35 was derived or why no scaling factor is required for larger units (see Comment III.1.4). Since no basis is provided for the \$80/kW cost or the scaling factors in the draft oil- and gas-fired SCR cost equations, API recommends that these equations not be included in the final document.

**Response:** The Agency derived these cost equations by analyzing the power sector to reflect SCR retrofits for oil and gas-fired units. These equations represent an approach to obtain a budgetary- or study-level cost estimate relatively quickly based on unit capacity. Previous versions of IPM have used these equations, and the Agency did not receive any substantive comments to lead EPA to revise them in the course of review of the latest IPM model versions (versions 5.13 to 5.15). These equations for oil and gas-fired units are separate from the cost equations developed by Sargent & Lundy. These equations are not intended to extensively reflect site specific project details, which are better served by the provision of vendor estimates. The commenter suggests the agency create a more granular cost approach, but our approach is consistent with a study-level cost estimate, which is the level of accuracy for costs in this Cost Manual.

EPA notes that units greater than 500 MW in size are usually not gas- or oil-fired; therefore, limited information for SCR applications exists among units of this size. The agency does not anticipate any SCR retrofits for oil / gas units exceeding 500 MW, but for estimating cases, the 500 MW obtained values (\$/kW) should be used for larger units.

#### *Comments on the “1.3” factor*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Section 2.4.1.1 (page 2-57) includes a factor of 1.3 applied to TCI to account for engineering, construction management, labor adjustment, and contractor profit and fees. However, engineering is typically 20%, construction management 10%, adjusting labor to pay time and a half for the last two hours of 10-hour shift adds 10% to labor cost, and contractor profit and fees are at least 10%, for a total of 50%, not 30%.

**Response:** The 1.3 factor is used to adjust the TCI for engineering and construction management costs, labor adjustment, and contractor profit and fees. The factor comes from the IPM and was developed based on input from industry. The IPM is revised periodically to incorporate new data, with each version of the model subject to a peer review process prior to being finalized. In addition, the IPM is often revised in response to public comments for EPA rulemakings in which the model was used. As we noted in Section 2.4.1.1, the 1.3 factor already includes a labor adjustment for time-and-a-half pay for 10-hour work shifts, contractor profit and fees, and engineering and construction management costs. We therefore disagree with the commenter's recommendation that the factor be raised to 1.5 to allow for 20% engineering, 10% construction management, 10% labor cost, and 10% contractor profit and fees. While these costs may be higher for retrofit projects with more challenging site-specific issues, we consider the 1.3 factor included in the IPM model to be a reasonable estimate of costs. As discussed later in this document in our responses to retrofit costs, we have revised the TCI equations to reflect total capital costs for new construction and added a retrofit factor that enables the total capital costs (including the management and engineering costs) to be adjusted based on the level of difficulty of a retrofit project.

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** The 1.3 factor does not appear in all the Chapter 1 and 2 TCI equations. This factor reflects real costs and EPA should demonstrate that those costs are included in the equations where the factor is not explicitly shown.

**Response:** The 1.3 factor is a multiplier that is made up of three components: 1) engineering and construction management, 2) premium shift labor expenses, and 3) contractor profit and fees - (10% + 10% + 10% = 30% or a 1.3 multiplier). For more information, please refer to the EPA SCR memorandum at [https://www.epa.gov/sites/production/files/2015-08/documents/attachment\\_5-3\\_scr\\_cost\\_methodology.pdf](https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-3_scr_cost_methodology.pdf). This multiplier is specific to the coal-fired unit based equations, and should not be used with the oil and gas-fired cost equations that were developed in a separate effort.

### ***Retrofit Factor***

**Commenter: Sierra Club and National Parks Conservation Association**

**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** *Retrofit Factor*

Many SCRs are installed on existing sources that present retrofit issues, such as space constraints, inadequate ID fan capacity, or require electrical and control system upgrades, compared to a new system in which the SCR is designed with the source. The proposed costing method includes a "retrofit factor" to adjust the cost estimate to site specific "retrofit" conditions.

The cost equations are based on “average” retrofit difficulty, equivalent to a retrofit factor of one. This raises two issues.

First, a retrofit factor of one is not suitable for a new facility, as it includes “average” retrofit difficulty, which doesn’t exist for a new facility. In addition, this factor must be modified to address any non-typical issues, such as the need to run a long segment of duct due to site congestion.

The SCR chapter does not articulate what is included in an “average” retrofit factor of one nor does it include any guidance on how to select it or adjust it for a new unit. The SCR chapter should be updated to include guidance on selecting this key input. This factor should be based on site visits where possible and facility plot plans, supplemented by analysis of aerial photographs to identify any layout constraints.

**Response:** For the response to this comment, please see the response below describing the revisions EPA made to the TCI equations to allow costs for new construction to be estimated as 80% of those for an average retrofit project.

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** The capital cost of retrofitting SCR to a coal-fired electric utility generating unit is influenced by many factors. However, EPA failed to account for the factors that are most relevant to the capital cost of SCR retrofits: the need to configure the reactor into an existing plant site and the resulting special construction needs. See the Cichanowicz Report at 3-1. In particular: retrofit reactors may be relatively far removed from the economizer outlet; the reactor inlet elevation may be higher than the economizer outlet; the resulting extended ductwork may require upgrading gas handling equipment; and site access for construction may be limited. EPA improperly overlooks these factors in the Draft SCR Chapter. This oversight is unreasonable, particularly given that the coal-fired units to which the CCM is most likely to be applied will almost certainly be existing units that implicate some or all of these issues.

**Response:** While long flue / duct runs in power plants exist, the SCR typically resides near the furnace to reduce duct run length and sustain a higher temperature entering the catalyst bed. This nearby location allows SCR to operate under a wider range of boiler loads to affectively reduce NOx. Consequently, the agency believes modifying the retrofit factor for long duct run lengths is in appropriate. Regarding new facilities, by definition, new construction is not a retrofit. Regarding site specific configuration, aerial photographs, plot plan drawings, etc., the agency did not intend the S&L tools to reflect site specific project details; rather, these cost estimating tools were designed to provide quick results within the immensely large IPM universe based on readily available public data for modeling economic dispatch. Examining site pictures and plant layout is a time intensive effort and, by its very nature, subjective and not conducive to running the IPM model. The casual observer would be unfamiliar with the engineering design concepts to create a cost effective retrofit and therefore is unqualified.

The commenter suggests the agency create a more granular approach resulting in a more accurate estimate than a study-level one – this was not the agency’s intention for this tool – the tool was created for IPM. The merits of the S&L cost tools (as applied to coal-fired units) allows users



the ability to quickly estimate costs and compare technologies. The S&L tools were not meant to establish a definitive price for awarding contracts. The accuracy, as desired by the commenter, encroaches upon a “level of effort” detailed proposal (as the A/E industry defines), which often requires hundreds of man-hours to complete. As such, the agency feels industry experts familiar with supplying retrofit emissions controls equipment at a profit or loss are best situated to assess site specific issues with minimal subjectivity to minimize risk and remain competitive. Consequently, the Agency retains a 1.0 retrofit factor to reflect the Agency’s conclusion that these costs are associated with an average level of SCR retrofit difficulty. IPM documentation articulates the “average” and associated accuracy with Sargent & Lundy’s SCR work; they can be found on p.1 “SCR Cost Development Methodology”; March 2013 [link: [https://www.epa.gov/sites/production/files/2015-08/documents/attachment\\_5-3\\_scr\\_cost\\_methodology.pdf](https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-3_scr_cost_methodology.pdf) ]

It is true that the S&L data set used to develop the cost calculations includes both SCR retrofits and new installations. As we noted in the revised draft, the IPM may overestimate costs for new units since the S&L data used by the IPM indicates that the majority of the projects were retrofits. To address the differences for new and retrofit units, we added a retrofit factor (RF) to each TCI equation that enables the TCI to be adjusted based on the level of difficulty of a retrofit project. A retrofit factor of 1 is used for average retrofits, which is the expected level of retrofit difficulty consistent with the S&L cost tool referenced in this SCR Cost Manual chapter as we mention earlier in this response. For new construction, a factor of 0.8 was used, which is consistent with a capital cost for new projects that is appropriately less than that for an average retrofit.

## **Contingency**

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Commenter: San Joaquin Valley Air Pollution Control District**

**DCN: EPA-HQ-OAR-2015-0341-0027-A2**

**Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.**

**DCN: EPA-HQ-OAR-2015-0341-0022-A1**

**Comment from commenter 0028:** The contingency cost for EPA’s capital cost estimating procedure should be 50 percent. The structural steel for a complex installation can be very expensive and increasing fan capacity and changing air preheater layout could increase costs considerably.

**Comment from commenters 0026 and 0024:** EPA should add \$80-110/kW to capital cost as contingency. EPA's cost estimating method is adopted from a procedure developed by Sargent & Lundy for the Integrated Planning Model (IPM). This procedure is based on cost data that is heavily biased to pre-2008 installations. EPA's predicted SCR capital cost as a function of generating capacity is almost identical to that reported by UARG in 2013 for SCR process equipment retrofit between 2008 and 2011. However, the cost to install SCR since 2011 significantly exceeds the cost reported in the 2008-2011 timeframe. EPA's cost estimating procedure may be adequate as a lagging indicator for units retrofit before 2011, but does not accurately predict future SCR cost. UARG suggest \$80-110/kW be added to the EPA cost estimate as a contingency to account for the increase in the future costs. On a percentage basis this translates to *the addition of 30-50%* of EPA's predicted cost. It should be noted that some recent units incurred capital cost \$200/kW greater than predicted by EPA.

**Comment from commenters 0026 and 0024:** One reasonable estimate of contingency could be the difference in EPA's predicted cost and that derived from the post-2011 UARG data (excluding the lowest and highest values). Using this definition of contingency, the projected SCR capital cost would be increased by an additional \$80-110/kW. The \$80-110/kW contingency value is derived by comparing a logarithmic correlation of post-2011 UARG-reported capital costs with the mean cost derived using IPM for bituminous and PRB coal. For a 200 MW unit bituminous and PRB unit, the cost estimated by IPM is \$310/kW while the cost derived from 15 post-2011 UARG-reported units (excluding the highest and lowest of the 17) is \$390/kW. At 850 MW the mean of bituminous and PRB cost from IPM is \$240/kW and the post-2011 UARG-reported cost is \$352/kW. Some post-2011 SCR retrofit projects incurred a capital cost \$200/kW greater than predicted by EPA. This variance is an approximate 30-50% increase from the IPM. Hence, a contingency 30-50% above EPA's predicted cost should be included.

**Comment from commenter 0020:** A Contingency of at Least 30% should be Included in SCR Total Capital Investment (TCI) Cost Estimates. No contingency appears to be included in the TCI estimates in the updated draft of the SCR, although a 5% process contingency is applied to the installation costs and a 15% project contingency was applied to the overall project cost in the current SCR Chapter.

A contingency factor should be included to address the following factors:

- Contingency factors are required for all project cost estimates, since direct estimates, particularly those based on only rough screening quality information, cannot anticipate every project need or impact. All potential siting and installation issues, required upgrades to electrical, instrument or other utility services; labor cost variations, and weather effects cannot be predicted in a screening quality estimate. Typically, project contingency factors used by the petroleum industry start quite high (e.g., 30-50%) and are reduced as project detail improves. However, even for projects with detailed process designs, project contingencies of at least 10-20% are still required (depending on company practice and experience).
- The underlying cost information may not be accurate. Reports of costs for installed projects tend to be incomplete because project accounting systems are segmented and often do not count all indirect costs, costs charged to on-going operations (such as required utility upgrades and equipment preparation costs), outage costs, etc.

Retrospective reviews may also fail to include costs from ancillary facilities managed as a separate contract or project or that is classified as maintenance, even though it is required for the project. Specific equipment that is often missed in such look-back reviews include monitors, upgrades to existing ID fans and their electrical supply, the cost of an SCR bypass (often needed on startup and for emergencies), and incremental additions to the DCS, instruments, and other general plant facilities.

- The data on utility boilers may not be representative of smaller industrial boilers. Utility boilers typically are 100 MW or larger, while industrial boilers are typically smaller than 100 MW. Industrial boilers are of different designs than utility boilers and often have different operating and siting issues. Sargent and Lundy indicate the costs for SCR increase rapidly for utility boilers under 100MW (about 1100 MMBTU/hr. for oil-fired units and 820 MMBTU/hr. for gas-fired boilers) and, thus, the costs curves derived primarily from larger utility boilers may be questionable for smaller industrial boilers.<sup>38</sup>
- There will likely be increased complexity and cost associated with future SCR installations because the easier installations were retrofitted first. Typically, control requirements first apply to equipment that can be most readily retrofitted and later to equipment that is more difficult to retrofit; therefore, it is reasonable to expect data from the 1990s and 2000s understates the costs for SCR installations after 2010.
- A significant contingency is necessary when estimating industrial boiler costs that are based on average historical cost data. Average cost data might be acceptable for developing national averages, but not for making cost benefit decisions for individual combustion device NO<sub>x</sub> controls. Since the boiler cost equations are based on average information, a contingency adjustment is necessary to assure the cost estimated for an individual project is valid and the cost benefit of a potential control decision is properly evaluated.

API recommends a contingency of at least 30% be applied to industrial boiler estimates derived from the draft cost estimating equations. API members indicate that 30 – 50% is the amount of contingency typically required for screening estimates, such as those developed through the Control Cost Manual. Such a contingency factor is consistent with the statement on page 2-2 of the draft Chapter that “The cost methodology incorporates certain approximations; consequently, it should be applied to develop study-level accuracy ( $\pm 30\%$ ) cost estimates ....”.

**Comment from commenter 0027:** In response to EPA’s question as to what a reasonable estimate of contingency is, whether it be for one or more types of contingency, the District recommends adding a contingency factor in the total capital investment costs for SNCR and SCR installation and retrofit. Specifically, the District recommends maintaining the process contingency between 5-10% due to uncertainty in the process operation and including a project contingency of 15% for uncertainties in project installation. These assumptions are based on 2010 information prepared for the Utility Air Regulatory Group’s report titled “Current Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies (see [http://www.publicpower.org/files/pdfs/uargscr\\_fgdfinal.pdf](http://www.publicpower.org/files/pdfs/uargscr_fgdfinal.pdf)).

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<sup>38</sup> Sargent and Lundy Report to Systems Research and Applications Corporation, *IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Final Report*, March 2013.

**Comment from commenter 0022:** The EPA did not include an estimate of contingency factor in the draft chapter but asked for comment on a reasonable estimate for a contingency factor. A contingency factor is appropriate to include, especially in retrofit applications. Based on our members' experience, a reasonable contingency factor would be in the range of 10 to 15 percent, or even higher depending on site-specific conditions.

**Response:** The capital cost procedure in the Sargent and Lundy SCR cost documentation of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 15 percent. These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with current recommendations on percentages for these contingencies by the Association for the Advancement of Cost Engineering International (AACE International) and procedures followed by EPRI, DOE, and EPA. The percentages also are consistent with percentages stated in the UARG report that was cited by one of the commenters. Given the maturity of SCR technology, relatively low process and project contingencies are appropriate, and no changes to the chapter are needed in response to the comments.

For clarification, we have added the following sentence to Section 2.4.1:

“The capital cost equations included in the manual reflect a process contingency of 5-10 percent and a project contingency of 15 percent.”

**Commenter: Xcel Energy**

**DCN: EPA-HQ-OAR-2015-0341-0029-A2**

**Comment:** Section 1, Chapter 2 of the Manual has a discussion of accuracy of cost estimates related to what point in time the estimate is completed in relation to project implementation. The suggestion is that estimates produced with the Manual's methods would primarily be done during the study phase, with an accuracy of  $\pm 30\%$ . Therefore, a contingency factor of 30% would be considered appropriate and should be included in the Manual for SCR cost estimate calculation.

**Response:** The level of accuracy for a cost estimate is a separate calculation to that for contingency. Thus, a study-level accuracy of  $\pm 30\%$  does not imply that the contingency should be 30%. See the response to the comments above in this section for a discussion of the contingency factor for SCR cost estimates.

### ***Owner Costs and AFUDC***

**Commenter: Xcel Energy**

**DCN: EPA-HQ-OAR-2015-0341-0029-A2**

**Comment:** EPA Should Include Owner's Costs and AFUDC Costs in Total Capital Costs

The Total Installed Cost (“TIC”) formula includes a 30% adder for engineering, construction management, and labor adjustment for 10 hour work shifts. The TIC formula should also include owner’s costs and allowance for funds used during construction (“AFUDC”), which are real costs incurred by companies that are paying to install SCRs at their facilities. For regulated utilities, PUCs are examining actual costs when determining whether project costs are eligible for cost recovery. PUC concerns arise when a project’s actual costs are higher, often much higher, than costs based on calculations using the Manual, which historically have been much lower than actual installed costs. Owner’s costs (owner activities related to engineering, management and procurement) and AFUDC are real costs incurred by the regulated utility that are not accounted for using the Manual methodology. Justifying rate recovery for actual project costs is made more difficult as PUCs focus on the lower cost used by EPA to justify EPA’s regulatory decision to require the expense. For the reasons provide above, EPA should include owner’s costs and AFUDC costs in total capital costs.

**Response:** Section 2.4 includes statements that owner’s costs and AFUDC are not allowed costs under the Control Cost Manual methodology, which is based on the “overnight” method for estimating capital costs. The Control Cost Manual follows a consistent approach that excludes these costs for estimating TCI across all chapters in the document.

### ***Correct Units***

**Commenter: American Petroleum Institute (API)**  
**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** The Units and Explanations for Equations 2-52 and 2-53 for Calculating Oil and Gas Fired Boiler SCR TCI Need to Be Clarified to Use the Correct and Consistent Units.

On pages 2-62 and 2-63 of the draft Chapter 2, equations are provided for estimating the TCI for installation of SCR for oil-fired industrial boilers  $\geq 275$  MMBTU/hr. and gas-fired industrial boilers  $\geq 205$  MMBTUhr. These equations are based on EPA’s assumed cost of \$80/kW of electricity generation for a utility oil- or gas-fired boiler as presented in equation 2-45. EPA has converted the \$80/kW in Equation 2-45 to  $\$7.27 \times 10^{-3}$  per MMBTU/hr. for oil-fired industrial boilers and  $\$9.76 \times 10^{-3}$  per MMBTU/hr. for gas-fired industrial boilers. However, the conversion is incorrect.

According to EPA in Equation 2.4, the conversion factor for oil is 11,000 BTU/kW and for gas is 8,200 BTU/kW. Thus, the correct cost factors should be  $\$7.27 \times 10^{-3}$  per BTU/hr. for oil-fired industrial boilers and  $\$9.76 \times 10^{-3}$  per BTU/hr. for gas-fired industrial boilers. Specifically, in equations 2-52 and 2-53, these factors, while identified incorrectly, are treated correctly because the equations include a term to multiply the unit capacity, which is in MMBTU/hr. by 1,000,000 to convert the capacity from MMBTU to BTU. Our specific recommended corrections to the equations and discussion are presented in Section 4.4.3 and 4.4.4 below.

Rather than making the specific changes we recommend Sections 4.4.3 and 4.4.4, it would be better to put these factors into \$/MMBTU/hr. (i.e., \$7,270 per MMBTU/hr. for oil-fired industrial boilers and \$9,760 per MMBTU/hr. for gas-fired industrial boilers) and take the

1,000,000 factor out of these equations. That will make them consistent with all the other equations presented in the cost section and thus reduce confusion and increase clarity.

Chapter 2, Page 2-62, First paragraph of Section 2.4.1.3.

“2,200 BTU/hr for an oil-fired boiler” should be “2,200 MMBTU/hr for an oil-fired boiler” and “BTU/kwh gives an estimated cost of  $7.27 \times 10^{-3}$  \$/MMBTU/hr” should be “BTU/kwh gives an estimated cost of  $7.27 \times 10^{-3}$  \$/BTU/hr.”

Chapter 2, Pages 2-62 and 63.

In equations 2-52 and 2-53, the units of the cost constant should be shown as \$/BTU/hr not \$/MMBTU/hr.

**Response:** The EPA agrees with the commenters that the equations do not show the appropriate units. As suggested by one of the commenters, units of MMBtu/hr are consistent with other equations in the SCR chapter, so Equations 2-52 and 2-53 have been revised to the \$ per MMBtu/hr basis. The incorrect units in the draft revised section were an inadvertent error.

### ***Need for Calculation Worksheet***

**Commenter: Sierra Club and National Parks Conservation Association**

**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** *Spreadsheet Model Based on IPM*

The proposed costing method consists of numerous complex equations, spanning some 27 pages that prove difficult to understand and use. In order to use the proposed costing method, a user would have to create complex Excel spreadsheets to implement the recommended cost calculations, which could lead to inconsistencies and errors that would likely be difficult to detect. If EPA keeps the IPM method beyond simply an interim method (we believe this would be a mistake), we recommend that EPA assemble the SCR cost effectiveness equations in an unlocked Excel Spreadsheet Model that would be circulated for public review before it is released with the final SCR chapter and the final version posted to EPA’s website. This step would avoid numerous different versions of SCR cost calculations prepared by other parties that could hide egregious assumptions or are innocently riddled with errors, due to the complexity of the calculations involved. This step would make the SCR chapter much more useful and save applicants, permitting agencies, and the commenting public a significant amount of time and reduce errors.

**Response:** The Agency plans to offer an Excel spreadsheet on its Internet site that contains the equations and data within the final revised SCR chapter when the chapter is available to the public.

## *SO<sub>2</sub> Content*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** The AHF is defined as 1 if the “SO<sub>2</sub> content” of the coal is  $\geq 3$  lb/MMBtu, and zero if below. Flue gas SO<sub>3</sub> concentration and air heater outlet temperature affect air heater corrosion. The concentration of SO<sub>3</sub> and the amount of ammonia slip present in the flue gas affect air heater deposition. The threshold provided is arbitrary and does not accurately capture the potential for either air heater corrosion or deposition of ammonium bisulfate on the air heater baskets or other downstream equipment. On Page 2-62, the total capital investment (TCI) equation does not include APH cost for oil-fired units, but high-sulfur fuel oils can result in elevated flue gas SO<sub>3</sub> concentrations that lead to air heater deposition in the presence of ammonia slip.

**Response:** In accordance with the costing methodology used in the IPM, the total capital costs can be adjusted for air preheater modification when sulfuric acid or ammonium bisulfate deposition poses a problem. Based on information collected from industry, air heater modifications are generally required and additional costs incurred when the level of SO<sub>2</sub> is above 3 lb/MMBtu. The 3 lb/MMBtu threshold for coal was based on input from industry. The APH modification cost adjustment was not considered necessary for oil combustion since most fuel oil burned has low sulfur content to comply with other air regulations. For example, the maximum sulfur content of distillate and residual fuel oil burned in electric power plants in 2014 was 2.5 percent sulfur by weight (approximately 2.8 lbs SO<sub>2</sub>/MMBtu), according to data compiled by the Department of Energy, Energy Information Agency (see <http://www.eia.gov/electricity/data/eia923/index.html>). The IPM is revised periodically to incorporate new data and each version of the model is subject to a rigorous peer review process prior to being finalized. Therefore, we consider the model to represent a reasonable approach based on currently available information.

## *NO<sub>x</sub> Removal Efficiency*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** On page 2-58, the NO<sub>x</sub> removal factor assumes that the cost varies linearly, relative to a removal efficiency of 80%. However, the cost to design SCRs for efficiencies in excess of 90% is much greater, and applying a factor of 1.125 (90/80) underestimates the cost increase significantly.

**Response:** The S&L report explains that the NO<sub>x</sub> removal factor (NRF) variable is necessary to adjust the cost equations to more accurately reflect the actual costs in their cost database. The NRF variable (in Equations 2.41 and 2.48) that the commenter refers to is actually scaled by

raising the value to the 0.2 exponent. After scaling the factor, for SCR units achieving 80 to 95 percent NO<sub>x</sub> efficiency, the value would reflect an approximate adjustment of 0 to +3.5 percent, respectively (i.e.,  $(80/80)^{0.2}$  equals 1.0 reflecting 0 percent adjustment, and  $(95/80)^{0.2}$  equals 1.035 reflecting a 3.5 percent adjustment). For SCR units achieving less than 80 percent, the scaled NRF variable would reflect a downward adjustment. For SCR units achieving 70 percent NO<sub>x</sub> efficiency, the value would reflect an approximate adjustment of -2.6 percent (i.e.,  $(70/80)^{0.2}$  equals 0.974 reflecting a decrease of -2.6 percent).

### ***Monitoring Costs***

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** The Installation and Annual Costs for Continuous Monitors Should be Included in the Cost Estimates.

SCR and SNCR installations require continuous NO<sub>x</sub>, O<sub>2</sub> (and possibly CO), and sometimes NH<sub>3</sub> slip monitors to demonstrate continuous compliance. Few industrial boilers already have such instrumentation prior to SCR or SNCR addition, since compliance for NO<sub>x</sub> limits for equipment without add-on NO<sub>x</sub> controls is typically demonstrated through a performance test. Thus, continuous NO<sub>x</sub>, O<sub>2</sub> and/or CO monitor costs are rightfully project costs, along with a slip monitor in some cases<sup>39</sup>. The capital costs and the ongoing maintenance costs for such monitors are significant, yet the descriptive information in these Chapters and the electric utility industry basis on which these Chapters rely, do not indicate that the costs associated with these monitors are included. In fact, for SNCR and smaller SCR installations the costs for monitoring can be a significant portion of the total project cost. Our members indicate the costs for these monitors can reach and exceed \$500,000. This exceeds typical EPA estimates,<sup>4013</sup> because a new analyzer shelter, access platforms, and additional or upgraded electrical and instrumentation and data systems are often required.

Because continuous emission monitors are complex and are subject to significant regulatory requirements, at least two hours per day of instrument upkeep and QA/QC is required along with quarterly or annual Relative Accuracy testing for these continuous monitors. Continuous monitor upkeep to regulatory standards involves considerably more than the 0.5% of monitor cost that EPA assigns for maintenance of SCRs and 1.5% of monitor cost that is assigned to SNCR maintenance in the drafts.

**Response:** The studies referenced in the S&L SCR cost memo analyzed total project cost for units retrofitting an SCR over a period of more than 10 years. EGU units were required to install emissions monitors pre-dating the NO<sub>x</sub> SIP call program; therefore, S&L's study would exclude

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<sup>39</sup> Since ammonia slip is not usually expected to change quickly, it is often monitored using Stain tube monitoring. In such cases, the NO<sub>x</sub> monitor would have to measure both SCR inlet and outlet concentrations to allow calculation of the required ammonia rate. Such dual NO<sub>x</sub> units are higher cost than single outlet NO<sub>x</sub> monitors, because of the additional sampling system, switching hardware, and additional platforming and electronics needed.

<sup>40</sup> For instance, on page 2-18 of the draft Chapter 2, it is stated that "The capital cost for one ammonia slip monitoring instrument is estimated to be \$40,000 for a single measurement point and up to \$70,000 in capital cost for three measurement points [54]." With structural, utility, indirect and other required ancillary costs added, the actual cost of this one monitor will be much higher and have a substantial impact on the total project cost for industrial boilers.



these costs. However, if an owner decided to update their monitoring systems, these would be included in the project cost.

A monitor's cost for the EGU sector will be greater than an equivalent like-in-kind monitor for the non-EGU sector. One should keep in mind that EGU facilities occupy significant land space. Thus, the electrical cable runs and supporting cable trays (on the order of thousands of feet) to transfer the signal represent a significant cost a non-EGU source will not experience. EGU's require significant ladders and platforms to reach monitors at their higher installed elevations – this will not be the case for the non-EGU sector. Consequently, the total cost for non-EGU monitors will be less.

Additionally, the EPA offers alternative, less costly, monitoring requirements for oil- and gas-fired units under the provisions of LME (Low Mass Emitting) [40CFR Part 75]. Under these applicable circumstances, fuel flow measurement into the system suffices.

Regarding maintenance costs, the EPA has not regulated the non-EGU sector under 40 CFR Part 75. Monitoring of non-EGUs for NO<sub>x</sub> is done under a number of provisions specific to the type of source. For most non-EGUs, the use of NO<sub>x</sub> CEMs is not required. Other, less costly, monitoring requirements are in place.

Note that capital and operating costs for monitoring systems must be estimated separately using the methodology presented in Section 2, Chapter 4 (Generic Equipment and Devices) of the Cost Manual.

#### **2.4.2 Total Annual Costs**

##### ***Operator Labor for SCR***

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** It is Unreasonable to Assume There Are No Operator Costs Associated with SCR.

On page 2-64 of the draft Chapter 2, it is stated:

The procedures in Reference [8] estimate operating labor time as 4 hours per day. However, the SCR reactor is a stationary device with no moving parts. Further, the SCR system incorporates only a few pieces of rotating equipment (e.g., pumps, motors). Therefore, the procedures in this report assume the existing plant staff can operate the SCR from an existing control room. In general, operation of an SCR system requires no additional, or only minimal, operating or supervisory labor.

It is unreasonable to ignore the cost conclusion from the IPM (i.e., reference 8), when virtually every other IPM assumption has been adopted in this draft without change, including the unusually low annual maintenance cost estimate discussed next. Furthermore, the logic presented for assuming no operator costs is invalid, since it ignores the operator time associated with the reagent and soot blowing systems. These systems require operator effort in unloading the ammonia safely, monitoring the ammonia system for leaks and potential problems, managing

the reagent inventory, managing startup and shutdown of the SCR system, managing the soot blowing system, and preparing equipment for and overseeing maintenance activity. Particularly given the low maintenance cost estimate and ammonia's toxicity, it is important that the operator hours involved in preparing equipment for maintenance and overseeing that maintenance to assure there are no safety issues are recognized.

**Response:** The EPA agrees that additional operating labor costs should be included in the TAC. In the final revised section, the approach follows the IPM model assumption of 4 hours/day operating labor.

### ***Operator Labor for Monitoring, Continuous Monitors for SCR***

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Page 2-69 states that additional labor is not required to operate the SCR system. However, additional labor could be needed to operate and maintain the additional instrumentation and monitoring systems required. Costs of installing, testing, maintaining, and operating additional monitoring equipment (e.g., NO<sub>x</sub> and ammonia analyzers) are not insignificant.

**Commenter:** American Petroleum Institute (API)

**DCN:** EPA-HQ-OAR-2015-0341-0020-A1

**Comment:** The Installation and Annual Costs for Continuous Monitors Should be Included in the Cost Estimates.

SCR and SNCR installations require continuous NO<sub>x</sub>, O<sub>2</sub> (and possibly CO), and sometimes NH<sub>3</sub> slip monitors to demonstrate continuous compliance. Few industrial boilers already have such instrumentation prior to SCR or SNCR addition, since compliance for NO<sub>x</sub> limits for equipment without add-on NO<sub>x</sub> controls is typically demonstrated through a performance test. Thus, continuous NO<sub>x</sub>, O<sub>2</sub> and/or CO monitor costs are rightfully project costs, along with a slip monitor in some cases<sup>41</sup>. The capital costs and the ongoing maintenance costs for such monitors are significant, yet the descriptive information in these Chapters and the electric utility industry basis on which these Chapters rely, do not indicate that the costs associated with these monitors are included. In fact, for SNCR and smaller SCR installations the costs for monitoring can be a significant portion of the total project cost. Our members indicate the costs for these monitors can reach and exceed \$500,000. This exceeds typical EPA estimates,<sup>42</sup> because a new analyzer

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<sup>41</sup> Since ammonia slip is not usually expected to change quickly, it is often monitored using Stain tube monitoring. In such cases, the NO<sub>x</sub> monitor would have to measure both SCR inlet and outlet concentrations to allow calculation of the required ammonia rate. Such dual NO<sub>x</sub> units are higher cost than single outlet NO<sub>x</sub> monitors, because of the additional sampling system, switching hardware, and additional platforming and electronics needed.

<sup>42</sup> For instance, on page 2-18 of the draft Chapter 2, it is stated that "The capital cost for one ammonia slip monitoring instrument is estimated to be \$40,000 for a single measurement point and up to \$70,000 in capital cost for three measurement points [54]."

shelter, access platforms, and additional or upgraded electrical and instrumentation and data systems are often required.

Because continuous emission monitors are complex and are subject to significant regulatory requirements, at least two hours per day of instrument upkeep and QA/QC is required along with quarterly or annual Relative Accuracy testing for these continuous monitors. Continuous monitor upkeep to regulatory standards involves considerably more than the 0.5% of monitor cost that EPA assigns for maintenance of SCRs and 1.5% of monitor cost that is assigned to SNCR maintenance in the drafts.

**Response:** The studies referenced in the S&L SCR cost memo analyzed total project cost for units retrofitting an SCR over a period of more than 10 years. EGU units were required to install emissions monitors pre-dating the NO<sub>x</sub> SIP call program; therefore, S&L's study would exclude these costs. However, if an owner decided to update their monitoring systems, these would be included in the project cost.

A monitor's cost for the EGU sector will be greater than an equivalent like-in-kind monitor for the non-EGU sector. One should keep in mind that EGU facilities occupy significant land space. Thus, the electrical cable runs and supporting cable trays (on the order of thousands of feet) to transfer the signal represent a significant cost a non-EGU source will not experience. EGU's require significant ladders and platforms to reach monitors at their higher installed elevations – this will not be the case for the non-EGU sector. Consequently, the total cost for non-EGU monitors will be less.

Additionally, the EPA offers alternative, less costly, monitoring requirements for oil and gas fired units under the provisions of LME (Low Mass Emitting) [40CFR Part 75]. Under these applicable circumstances, fuel flow measurement into the system suffices.

As for maintenance costs – the EPA has not regulated the non-EGU sector under 40 CFR Part 75. Monitoring of non-EGUs for NO<sub>x</sub> is done under a number of provisions specific to the type of source. For most non-EGUs, the use of NO<sub>x</sub> CEMs is not required. Other, less costly, monitoring requirements are in place.

Note that capital and operating costs for monitoring systems would be estimated separately using the methodology presented in Section 2, Chapter 4 (Generic Equipment and Devices) of the Cost Manual.

### ***Maintenance Cost for SCRs***

**Commenter: American Petroleum Institute (API)**  
**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

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With structural, utility, indirect and other required ancillary costs added, the actual cost of this one monitor will be much higher and have a substantial impact on the total project cost for industrial boilers.

**Comment:** The Assumed Annual Maintenance Cost of 0.5% of TCI is Unreasonable for Industrial Boilers.

The current Chapter 2 of the EPA Control Cost Manual estimates SCR annual maintenance costs as 1.5 % of the TCI. It is proposed to change that value to 0.5%. EPA explains the changes as follows, on page 2-64 of the draft:

[The IPM] applies the 0.5% factor for units smaller than 300 MW and applies 0.3% for larger units, and the factor is applied to the “Base Module” cost rather than the TCI (i.e., the equipment and installation cost before adding 30% for engineering and construction management, labor adjustment, and contractor profit and fees). Since the capital cost estimating procedure for oil- and gas-fired units does not include estimation of a Base Module cost, the procedures in this report use the more conventional approach of scaling the annual maintenance cost from the TCI.

This discussion explains the mechanics of the change in estimated maintenance costs, but provides no justification for the 0.5% estimate itself and no justification appears to be presented in the IPM documentation. Nor is there any explanation as to how a maintenance estimate for 300 MW utility boilers applies to much smaller industrial boilers. Maintenance costs do not scale down as a function of firing and it would be expected that the maintenance costs (ex. catalyst cost) would not be much different for a small SCR unit than for a larger one. For instance, the reagent system for an industrial boiler SCR has the same components, just somewhat smaller, as does a utility SCR system. Thus, it would be expected that the percentage of TCI would be higher for smaller SCR units (i.e. industrial boiler SCRs than for the larger utility boiler SCRs).

While the SCR catalyst housing itself should not require much maintenance, that housing is instrumented and the reagent system<sup>43</sup>, the soot blowing system, and the required ammonia area monitors and stack continuous emission monitors will require a higher annual maintenance cost than 0.5% of TCI for industrial boilers, particularly if no provision is included in the annual cost for the operator time to prepare equipment and oversee the maintenance.

**Response:** The Sargent & Lundy cost memo documents cost estimating tools for IPM and these apply to coal-fired units. They do not apply to oil / gas fired units. The oil / gas equations pre-date the S&L work and utilize a different format; they underwent review by experts within EPA and outside in previous IPM versions released to the public. The combustion gas stream exiting oil / gas fired units are extremely cleaner compared to a solid fired unit; subsequently, the maintenance cost factors are lower due to this cleaner fuel (no ash, no catalyst poisons, low sulfur, no mercury, etc.).

The approach used in the IPM method does appear to be consistent with the commenter’s point that the maintenance cost percentage of TCI would be higher for smaller SCR units (and by corollary the percentage would be smaller for larger units). The use of a larger percentage (0.5 percent) for smaller units <300 MW and use of a smaller percentage (0.3 percent) for larger units

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<sup>43</sup> Reagent system maintenance typically includes: ammonia unloading system monitoring, ammonia tank unloading, ammonia risk management plan, ammonia tank inspection, maintenance of ammonia pumps, dilution air blowers, supporting components, and annual ammonia injection grid tuning.

≥300 MW does reflect the commenter's statement that maintenance costs would be similar no matter the unit size. While the commenter notes that industrial boilers tend to be smaller in size, the equations apply to comparably sized boiler units with heat rates of roughly >250 MMBtu/hr, no matter whether the unit is for utility or industrial purposes. Boiler units that are below 25 MW or 250 MMBtu/hr, whether utility or industrial, would not be able to use the Cost Manual approach to estimate TCI and TAC.

The commenter also indicates that maintenance costs for monitoring and CEMS would be higher than 0.5 percent. Note that the monitoring costs are not discussed in this section of the Control Cost Manual. The capital and operating costs for monitoring systems must be estimated separately using the methodology presented in Section 2, Chapter 4 (Generic Equipment and Devices) of the Control Cost Manual.

### ***Impact of Economizer Bypass on Boiler Efficiency***

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Page 2-64 suggests that the 'small decrease in boiler efficiency due to the operation of the economizer bypass' is not significant. This is not accurate; a small amount of bypass can result in a sizeable cost penalty.

**Response:** The primary purpose for the economizer bypass is to prevent sulfuric acid condensation, which in turn corrodes the metal duct work. SCR catalyst can be formulated and sized to accommodate lower gas temps, but in general, the economizer bypass is only required during periods of low loads, and losses in boiler efficiency will be experienced only during these periods. Other options can include absorbing the SO<sub>3</sub> (the precursor to sulfuric acid) to allow lower operating temps, or selecting an SCR catalyst formulation which produces less SO<sub>2</sub> to SO<sub>3</sub> conversion. The owner has many options besides installing an economizer by-pass.

The EPA disagrees that bypass causes a sizable cost penalty. One source indicates there may be a 1 percent drop in efficiency for every 40°F increase in the air heater outlet temperature.<sup>44</sup>

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<sup>44</sup> (Singer, J.G. (ed.) Combustion Fossil Power Systems. Third edition, Combustion Engineering, Inc., Windsor, CT. 1981.)

### *Costs for Additional Fuel and Ash Disposal*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** The Direct Annual Cost (DAC) equation on page 2-64 does not include cost for additional fuel and associated ash disposal due to efficiency decrease; these were included in the SNCR cost calculation and should also be included here in the SCR calculation.

**Response:** Costs for additional fuel usage and ash disposal have not been included in the final revised SCR chapter. In the SNCR, the ammonia-based reagent is injected into the furnace, where the water in the reagent solution evaporates thereby decreasing the steam generated and reducing the boiler efficiency. Consequently, more fuel must be burned in boilers equipped with SNCR to maintain the required steam flow. For this reason, estimates of the additional fuel cost and, for coal-fired plants, coal ash disposal costs were included in the direct annual operating costs for the SNCR. In the SCR, however, the reagent is injected into the exhaust stack at point downstream from the combustion unit. Because the reagent is injected downstream from the combustion chamber, the evaporation of the water does not impact the steam generated and the boiler efficiency. Hence, no additional direct annual costs for fuel and coal ash disposal would be incurred for operating an SCR.

### *Consistency across Equations*

**Commenter:** American Petroleum Institute (API)

**DCN:** EPA-HQ-OAR-2015-0341-0020-A1

**Comment:** Chapter 2, Page 2-65.

Equation 2-61 is the same as Equation 2-60 with the unit capacity converted from MW/hr to MMBTU/hr. However, for some reason the dimensionless factor in 2-61 is presented as 0.56/100, rather than as 0.0056 as it is in equation 2-60. To avoid confusion it should be changed in equation 2-61 to be the same as in equation 2-60.

**Response:** The EPA agrees and has made the revision in the final section.

### *Property Tax and Insurance Cost*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** Page 2-69 does not include property tax or insurance cost in the indirect annual cost estimate. We would like to note that the entire cost of these projects is not always exempt from property tax. In addition, a site may acquire insurance to cover the downtime necessary to install the pollution control project. Smaller companies that are not self-insured may purchase insurance specifically for a pollution control installation project.

**Response:** The calculation methodology for indirect annual costs is consistent with the method provided in the IPM. While we agree with the commenter that some plants may incur additional costs for property taxes and short-term insurance costs, we note that these costs are not applicable to all facilities and are likely to have negligible impact on the study-level estimates that have an accuracy of  $\pm 30$  percent. As explained in section 2.4.2 (Indirect Annual Costs), property taxes generally do not apply to pollution control equipment and insurance costs are generally minimal. However, as indicated in Section 1, Chapter 2 (Cost Estimated: Concepts and Methodology), property taxes and insurance costs may be included in the indirect annual costs if desired. These additional costs can be estimated in accordance with Section 1, Chapter 2 as 1 percent of the TCI for property taxes and 1 percent of the TCI for insurance costs.

### ***Return on Equity and Depreciation***

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** The factors used by EPA to calculate capital recovery cost grossly underestimate the annualized costs of installing SCR. The text on page 2-69 states that “[c]apital recovery cost is based on the anticipated equipment lifetime and the annual interest rate employed.” Any estimate based on these two factors alone is completely deficient, yet these are the only factors used by EPA in the equation for the capital recovery factor provided on page 2-70. The capital recovery factor should account for not only interest rates, but should also include return on equity, depreciation, inflation, and risk. The use of these factors is standard practice, as in Alstom, *Clean Combustion Technologies* 125 (Carl Bozzuto ed., 2009). In addition, the Federal government generally recognizes that cost estimates need to be based on much more than just equipment lifetime and annual interest. For example, cost estimates made by the Department of Energy routinely take into account the cost of equity, risk, the cost of debt, and the proportion of debt to equity in financing a capital project. *See, e.g.*, Technical Support Document, Energy Conservation Program: Energy Conservation Standards for Packaged Terminal Air Conditioners and Packaged Terminal Heat Pumps, EERE-2012-BT-STD-0029-0040, at 8-20 to 8-22 (June 2015).

**Response:** The capital recovery factor (CRF) is based on the equipment life and interest rate. This is part of the Control Cost Manual methodology and is consistent with its definition and use in the equivalent uniform cost (EUAC) method, a well-recognized approach to estimate annualized costs. Components of impacts such as return on equity, depreciation, inflation, and risk are part of the levelized cost method (LCM), a method for cost estimation that is used in the electric power sector. This LCM and the components just mentioned yield costs that include inflation and other factors that are not included in the EUAC method and thus not allowed in the Control Cost Manual methodology, a methodology that yields costs that do not include inflation (or real costs).

### ***Catalyst Life or Appropriate Catalyst Replacement Frequency***

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment: Chapter 2, Pages 68-69**

The last two paragraphs in the Catalyst Replacement section seem out-of-place. The bulk of the section deals with the two methodologies for estimating annual catalyst replacement costs, while these last paragraphs deal with catalyst amounts and lives and include one specific example of reheat and other costs associated with a 600 MW coal-fired utility boiler. These paragraphs should be moved into the appropriate earlier section of the Chapter section dealing with catalyst volumes, life, etc. since they have nothing to do with estimating the annualized cost of catalyst replacement.

**Response:** The EPA agrees that the last paragraph would more appropriately be placed earlier in the section, and this paragraph has been moved to the end of the “Tail-End SCR” subsection in section 2.2.3 in the final section. The EPA believes discussions of the catalyst life and expected operating hours do fit appropriately within the Catalyst Replacement subsection. The Catalyst Replacement subsection begins with discussion of the typical catalyst life for utility coal-fired units in high dust configuration. The two paragraphs below Equation 2.67 continue the discussion on the expected catalyst life for other types of configuration, specifically that low dust and tail-end units require less frequent catalyst replacement and have longer expected operating hours. The number of layers replaced at once may also be related to the configuration. Under Methodology 1, the number of layers replaced at a time is a parameter in Equation 2.63, and the Annual Catalyst Replacement cost in Equation 2.64 relies on parameters related to the expected operating life of the catalyst and the operating hours of the SCR (as shown in Equations 2.65 and 2.66). The previous sections deal with Original Catalyst Costs and Catalyst Life.

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** Regarding SCR operating costs, EPA’s methodology for estimating catalyst replacement costs also suffers from serious flaws. To determine this cost, it is essential to determine the correct catalyst volume. Yet to predict catalyst volume, EPA relies on an outdated 1998 study that fails to properly account for the key variable of the specific surface area offered by the catalyst. *Id.* at 4-3. EPA’s methodology also does not account for the cost of labor and equipment to replace the catalyst, which can be 30-60 percent of present catalyst market prices, or approximately \$1,500-3,000/m<sup>3</sup> of delivered catalyst cost. Further, the Agency assumes that one layer of catalyst can be replaced every three years. In reality, while the frequency of catalyst changeout varies with the fuel, reactor design, and application, a more reasonable assumption given industry practice is that an SCR reactor with four catalyst layers will replace one layer every two years. As to methodologies on which EPA solicited comment, UARG believes that EPA may reasonably use “Method 1” so long as the Agency accounts for the factors described above.

EPA’s proposed method to estimate annual catalyst replacement cost can be used but with proper and realistic inputs. Specifically, Equations 2.63 through 2.66 in the Draft SCR Chapter 2 can be



used but with the correct catalyst volume, catalyst replacement frequency, and including labor costs to remove “spent” catalyst and install replacement catalyst. Regarding catalyst volume, EPA uses an estimating procedure that does not explicitly employ the key design input of specific surface area, and as a result could underestimate catalyst volume by 20-25%. EPA by ignoring the labor cost to remove “spent” catalyst and install new catalyst leaves out a major cost factor. Further, EPA inappropriately interprets catalyst supplier guarantees, and does not consider that replacing catalyst must be scheduled with major maintenance outages. As a result a key example calculation prepared by EPA erroneously concludes a commercial SCR process on average will require one new catalyst layer every three years. In fact, catalyst replacement varies widely with fuel source, boiler operation, and process design. In practice replacing one layer in two years is common.

**Response:** As we noted in Section 1 of the SCR chapter, the methods described in the Cost Manual, including the method for estimating catalyst volume, are designed to provide study-level capital and operating cost estimates with an accuracy of  $\pm 30$  percent. We believe that the method provided for estimating the catalyst volume is consistent with this goal. However, catalyst volumes provided by SCR manufacturers should be used where more accurate cost estimates are required.

Regarding to the comment on the labor and other costs associated with catalyst replacement, the catalyst cost used in equations 2.63 (method 1) and 2.67 (method 2) should include the entire cost of replacing the catalyst, including the costs for installing new catalyst and removing and disposing of old catalyst. When using method 1 to estimate the annual catalyst replacement cost, we agree with the commenter that the expected operating life of the catalyst should be based on site-specific factors, such as the characteristics of exhaust gas entering the SCR and the type of catalyst used. We recommend that facilities seek the advice of catalyst vendors both for determining the appropriate catalyst volume and for estimating catalyst operating life.

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**  
**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment: CATALYST VOLUME**

A key input in estimating SCR operating cost is the annual catalyst replacement charge. The unit price for catalyst has significantly decreased in the last decade, but replacement charges still represent a large component of operating cost. Quantifying this cost requires knowledge of the catalyst volume and a realistic catalyst replacement schedule. EPA’s procedure to estimate catalyst volume is addressed in this section and the catalyst replacement schedule is addressed in Section 5.

EPA’s procedure to estimate the initial catalyst volume – a key input to operating cost – is based on an EPA-funded 1998 reference.<sup>45</sup> This early reference can only reflect experience from greenfield plants or the first generation of retrofits that were in service by the late 1990s – essentially ignoring almost two decades of operating experience. EPA’s procedure does not consider how key catalyst geometric characteristics such as cell opening or plate spacing should

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<sup>45</sup> *Selective Catalytic Reduction for NOx Control on Coal-Fired Boilers, Draft Report*, The Cadmus Group, Bechtel Power Corporation, and Science Applications International Corporation, prepared for the U.S. Environmental Protection Agency, May 1998.

be selected to reflect the plugging characteristics of certain coals; such decisions affect the catalyst specific surface area and volume required.

The catalyst specific surface area is a key variable determining catalyst volume. The Draft SCR Chapter 2 documentation cites a range of specific surface area that includes an unrealistically high value that is unsuitable for coal as the small cell opening or plate spacing would prompt ash deposition and the blocking of catalyst – EPA’s discussion ignores this key factor. EPA’s method to estimate catalyst volume is based on imbedded values of specific surface area that are not revealed and presumably appropriate for the period up to 1998 when experience was evolving. As a consequence EPA’s catalyst volume prediction can under-represent the required volume for many applications.<sup>46,47</sup>

The potential for underestimating catalyst volume is illustrated by an example case. Table 4-1 compares the estimated catalyst volume derived using several methods for a 520 MW unit fired by eastern bituminous coal, and designed to provide 90% NO<sub>x</sub> removal from 300 ppm (@ 0% O<sub>2</sub>) and control of residual NH<sub>3</sub> to 2 ppm, with catalyst addition required after 16,000 operating hours. Table 4-1 explicitly uses the concept of reactor potential to estimate catalyst volume.<sup>48</sup> The “EPA Method” shown in Table 4-1 uses EPA’s recommended relationship<sup>49</sup>, while a recent publication from a catalyst supplier employs the concept of reactor potential and estimates catalyst volume using a specific surface area typical of a plate-type catalyst (350 m<sup>2</sup>/m<sup>3</sup>).<sup>50</sup>

**Table 4-1. Comparison of Initial Catalyst Volume for 520 MW Eastern Bituminous Coal Reference Unit: EPA 1998 Methodology vs. Two Catalyst Suppliers**

	EPA Method	Catalyst Supplier
Reactor Potential, new (dimensionless)	Not Specified	5.8
Reactor Potential, at end-of-life (dimensionless)		4.2
Initial Catalyst Activity (m/h)		38
Catalyst Specific surface Area (m <sup>2</sup> /m <sup>3</sup> )		350
Projected or Assumed Catalyst Lifetime	24,000	16,000

<sup>46</sup> See Equation 2.22 on page 2-50 of Draft SCR Chapter 2. There is no explicit utilization of catalyst specific surface area in this relationship.

<sup>47</sup> Page 2-16 of Draft Chapter 1 cites a specific surface area range of 300-1,200 m<sup>2</sup>/m<sup>3</sup>; there is no discussion of the fact that most catalysts designed for coal present a specific surface area of 300-500 m<sup>2</sup>/m<sup>3</sup> and that values exceeding this range can present significant risk and are unrealistic for coal-fired application.

<sup>48</sup> Reactor potential (RP) is defined as  $RP = k/AV$ , where “k” is catalyst activity in units of m/hr and “AV” is area velocity, also in units of m/h. RP is thus dimensionless.

<sup>49</sup> Equation 2.22 of Draft SCR Chapter 2.

<sup>50</sup> Jeffers, Ken, *Misconceptions of Catalyst Performance, Training Class 5*, presented at Rheinhold Environmental 2012 NO<sub>x</sub>-Combustion Round Table, Columbus, OH, February 13, 2012. Graphic #11. (Attachment 3)

Catalyst Volume (ft <sup>3</sup> )	24,534	30,276
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Table 4-1 shows the EPA method results in a projection of 80% of the catalyst volume that is estimated using the procedures and assumptions from a supplier of catalyst with a plate-type geometry. As will be shown in Section 5, this shortfall in catalyst volume – although not affecting EPA’s estimate of capital cost – together with EPA’s inappropriate assumption of 24,000 hours between catalyst exchange results could under-predict operating cost.

**Response:** Available literature indicates that reactor potential is a recently developing modeling concept or approach that catalyst vendors use to estimate appropriate catalyst volumes for SCR systems. It appears that this approach involves proprietary procedures that cannot be represented or approximated by simple equations for inclusion in the SCR chapter of the Control Cost Manual. For example, the publication cited by the commenter (footnote 55) indicates that the reactor potential at the end of the catalyst life (i.e., the theoretical minimum reactor potential, or Pmin) is a function of the NOxin, NOxout, and ammonia slip, but no equation using these parameters is presented. Thus, it is not clear how the Pmin value of 4.2 in Table 4-1 was calculated. It is also not clear from the discussion in footnote 55 or from the comment how the catalyst volume of 30,726 ft<sup>3</sup> was calculated. Similarly, another discussion of reactor potential<sup>51</sup> described a 4-step process for determining the catalyst volume. The first step is to determine Pmin, which is based on “fixed operating conditions (flows, temp, etc.).” The second step is to estimate the catalyst deactivation rate based on “fuel quality, combustion parameters, and design life.” Using the values from the first two steps, the third step is determine the initial reactor potential (Po). Finally, step 4 is to determine the catalyst volume based on “Po, catalyst activity, geometry, SO2 to SO3 conversion rate, and various gas conditions and constituents.” Except for step 3, it is not clear how these steps could be represented in the chapter. For these reasons, we have not included the reactor potential as an approach for calculating catalyst volume in the revised SCR chapter.

We have also determined that the current approach in the chapter (i.e., Equation 2-22) provides an acceptable estimate of the catalyst volume based on the following information:

- Available information indicates that catalyst life is often longer than 16,000 years. In such cases it appears the reactor potential approach would estimate a smaller volume.
- A respected expert in the field performed a cost analysis<sup>52</sup> for SCR on 4 EGU boilers using Equation 2-21 that resulted in catalyst volumes very similar to the volumes calculated using Equation 2-22 for comparison. In this analysis, Kcatalyst (i.e., Kmin) was estimated using a typical value of 42.5 m/h for Ko and a Kmin/Ko ratio of 0.7 (comparable to the Pmin/Po ratio cited by the commenter). The catalyst specific area (Aspecific) was calculated from catalyst parameters to be 428 m<sup>2</sup>/m<sup>3</sup> (only slightly higher than the range cited by the commenter).
- The difference in volumes calculated by the commenter are within the stated study-level accuracy of ±30 percent for the Manual.

<sup>51</sup> Cochran, John, *Fuel Impacts on Design and Performance of SCR Catalysts*, presented at McIlvaine Hot Topic Hour, June 30, 2011.

<sup>52</sup> Andover Technology Partners, Costs of NOx BART Controls on Utah EGUs, October 22, 2015.

Oil / gas fired units do not experience the issues associated with solid fuel fired units; therefore, the comment is unsuitable for Oil / Gas fired unit cost equations. The comment fails to mention the purpose for increasing effective catalyst volume is to offset ash blinding / build-up issues. Ash build-up is a design deficiency allowing ash to build-up and obscures the catalyst active sites. This can be overcome by employing adequate ash removal systems or proper ductwork design to eliminate the issue.

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** On page 2-66 of the draft Chapter 2 it is reported, for the purposes of calculating ongoing catalyst costs, catalyst life was assumed to be 24,000 (approximately 3 years), consistent with typical catalyst manufacturer's guarantees. We have no additional information on catalyst life for oil-fired boilers, but our members report 5 years is a typical expected catalyst life in gas-fired boilers. Our members report little experience with catalyst replacements, since most installations are relatively new. However, our members indicate they expect to replace the entire catalyst bed in kind when replacement is necessary and they do not expect to deal with regenerated catalyst or replacement of individual layers. Thus, we would anticipate catalyst replacement cost to approximate initial catalyst costs, plus inflation. Presumably, this reflects 1) the relatively small amount of catalyst and thus lower total cost for oil- and gas-fired industrial boiler SCR installations compared to the much larger utility boilers and higher NO<sub>x</sub> from coal-fired units and 2) the typically short duration of industrial boiler outages requiring any catalyst change out to be completed as quickly as possible. Additionally, it is reported that catalyst is sometimes replaced before the design life is reached in order to take advantage of planned boiler and process outages in order to avoid an extra outage.

**Response:** The first methodology (cost methodology 1) for catalyst replacement costs may be used for both replacing all catalyst at once and for replacing one layer at a time. So either approach is appropriate for those facilities that replace the full catalyst and those that replace one layer. For full replacement, variable  $R_{layer}$  in Equation 2.63 would be 1, as noted in the chapter.

With respect to the information provided by the commenter for catalyst life for refinery units, we included a statement that SCR catalyst life on oil and gas-fired units is assumed to be 40,000 hours, as is consistent with the EPA-CICA Fact Sheet for SCR (Air Pollution Control Technology Fact Sheet, Selective Catalytic Reduction, EPA Publication No. EPA-452/F-03-032) and also included a statement that the catalyst life for gas-fired units has been reported to be up to 60,000 hours. The expanded discussion on catalyst life values for various types of units was included in section 2.4.2 subsection Catalyst Replacement as follows:

“For oil- and gas-fired units, the SCR catalyst life is assumed to be 40,000 hours, and the catalyst life for some gas-fired units has been reported to be up to 60,000 hours.”

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** Regarding catalyst replacement frequency, exchanging one layer of catalyst after filling the spare layer is the practice routinely followed in industry. This practice incurs the least longterm cost by continuing use of partially deactivated catalyst.

The most important input in determining catalyst replacement cost is the catalyst replacement frequency. EPA's source documentation on this topic matter is grossly outdated – citing references from 1991 and 1998.<sup>53</sup>

The frequency of catalyst changeout varies with the fuel, reactor design, and application. It is not possible to generalize a catalyst replacement frequency, even within coal rank. Generally, a given layer of catalyst is considered “spent” and appropriate for replacement when the activity is approximately 60-70% of the “new catalyst” activity value. The rate at which a catalyst will deactivate and approach the 60-70% threshold for replacement varies widely and depends on fuel composition and reactor design. For example, an assessment of catalyst deactivation rates for SCR-equipped units operated by Southern Company showed a wide variety of results.<sup>54</sup> Some units firing arsenic-containing eastern bituminous incurred aggressive deactivation as catalyst activity reduced to 65% of new values after 7,000-12,000 hours,<sup>55</sup> and certain PRB-fired units encountered the 65% threshold after 15,000 hours.<sup>56</sup> On the other hand, certain units fired by eastern bituminous fuels did not incur the approximate 65% threshold until 24,000 hours and greater.<sup>57</sup>

The addition of calcium to the fuel can at least partially mitigate the rate of catalyst deactivation from arsenic; but contrary to EPA's position experienced users note “there is no such thing as arsenic-resistant catalyst”.<sup>58</sup> Further, the firing of PRB fuel under “deep” staged conditions to derive low NO<sub>x</sub> can prompt rapid catalyst deactivation, requiring one layer of four to be exchanged annually.<sup>59</sup> The use of chemical additives or altering the firing conditions is reported to ameliorate the phosphorous-derived deactivation rate, although generalization to the entire industry inventory is not proven.<sup>60</sup> The variability in catalyst deactivation rates imposes an equal variability in catalyst replacement rates.

Figure 5-2 presents an example exchange rate based on one catalyst supplier's analysis for a unit firing eastern bituminous coal. The metric of Figure 5-2 is the total reactor potential as comprised of the reactor potential of 3 layers in the reactor. Figure 5-2 shows that four catalyst exchange “events” are planned, installing five new layers of catalysts, over about 80,000 operating hours. One catalyst supplier reported that depending on wall thickness a total of 12

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<sup>53</sup> Draft SCR Chapter, References 33 and 51.

<sup>54</sup> Hartenstein, H., et al., “Comparison of Deactivation Rates of Different Types of Catalyst”, presentation to the 2009 NO<sub>x</sub> Combustion – PCUG Conference, February, 2009, Akron, OH. (Attachment 4)

<sup>55</sup> Ibid graphic 19.

<sup>56</sup> Ibid graphic.

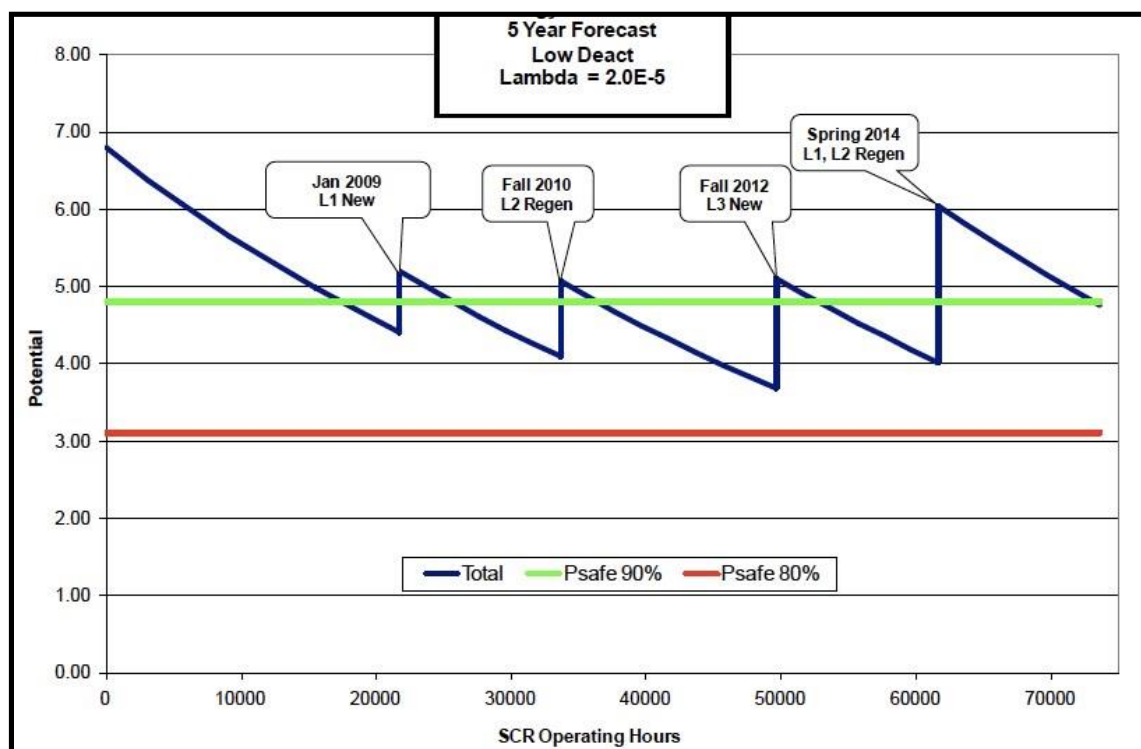
<sup>57</sup> Ibid graphics 9, 12.

<sup>58</sup> Ibid, graphic 4.

<sup>59</sup> Gadgil, M., et al., “Deactivation of Selective Catalytic Reduction (SCR) Catalyst by Phosphorous: Proposed Mechanism and Possible Solution, Paper presented to the 2012 Mega Symposium, August 30-September 2, 2010, Baltimore, MD. (Attachment 5).

<sup>60</sup> Ibid.

catalyst layers would be required in 20 years.<sup>61</sup> Less frequent catalyst replacement schedules can be found but the experience reflected in Figure 5-2 is common.



**Figure 5-2. Catalyst Exchange Frequency: Eastern Bituminous Coal**

Further, EPA does not recognize that other operating factors – most notably the deposition and blocking of catalyst surface area by fly ash – will lower reactor potential. EPA does acknowledge that such blocking by ash deposits exists – by describing the specific problem of Large Particle Ash.<sup>62</sup> But EPA does not consider the role of Large Particle Ash and other factors in projecting a realistic catalyst lifetime.

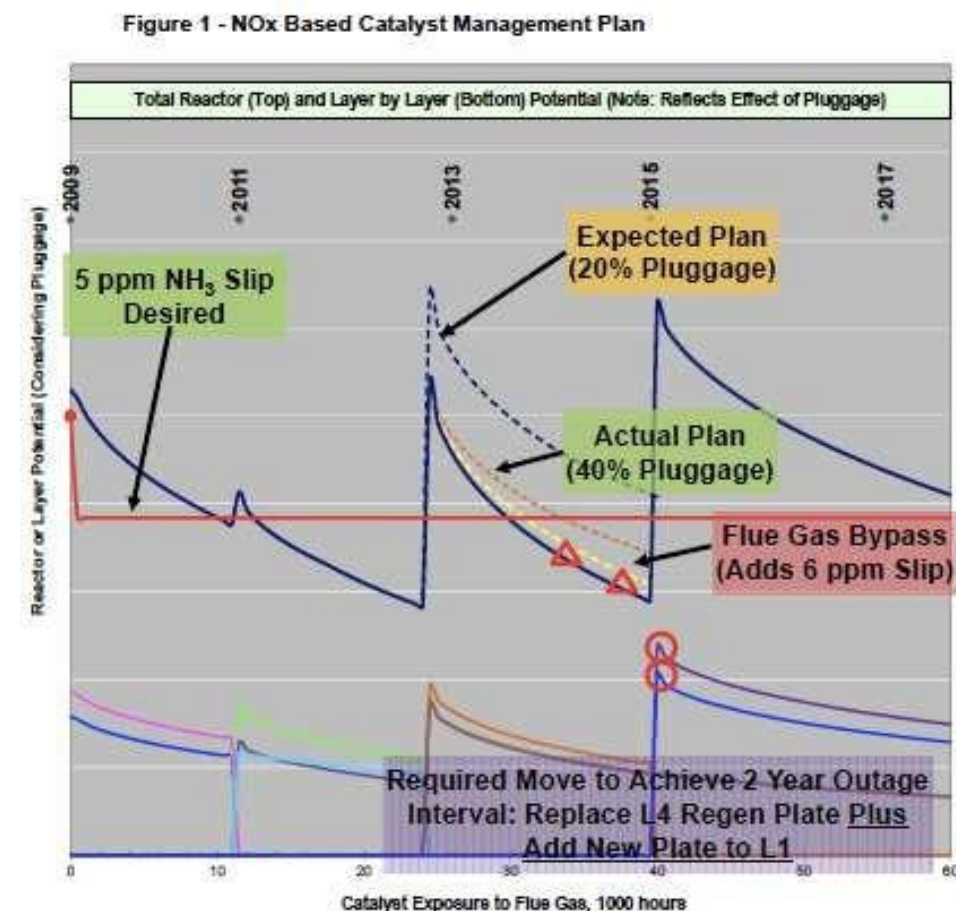
Figure 5-3 presents a more authentic catalyst management plan – showing the relative change in reactor potential for a large PRB-fired unit that incurred ash plugging.<sup>63</sup> Figure 5-3 shows the erratic rate of decay of reactor potential (on a relative basis) and how catalyst pluggage from ash affects the actual reactor potential realized. Figure 5-3 does show the owner abided by the original plan of a 24,000 operating hour changeout – but after about 12,000 operating hours the reactor potential was less than the minimum required for 5 ppm residual  $\text{NH}_3$  – meaning residual  $\text{NH}_3$  emissions were higher than planned. Figure 5-3 also shows how the role of catalyst pluggage can compromise reactor potential, and how in this case adding two layers of catalyst

<sup>61</sup> Winter, et al., *Comparing Plate & Honeycomb Catalyst: Myths and Realities*, presentation to the Reinhold Environmental 2014 NOx-Combustion Round Table, February 11, 2014. See graphic #21. (Attachment 6).

<sup>62</sup> Draft SCR Chapter, page 2-37.

<sup>63</sup> Cochran, et al., *Do Your Laboratory Activity Test Results Match Field Performance?*, presentation to the Reinhold Environmental 2015 NOx-Combustion Round Table, February 11, 2014. See graphic #42. (Attachment 7)

(changing one and adding a second to the empty spare cavity) is necessary to achieve 2 operating years between outages.



**Figure 5-3. Authentic Reactor Potential Decay: PRB Coal with Ash Blockage**

EPA cites the availability of guarantees from catalyst suppliers as a sufficient basis to construct a catalyst management strategy. Catalyst guarantees are of limited benefit – they typically assure that specified NO<sub>x</sub> removal can be provided for a given operating time, assuming the owner has maintained the specified process conditions, with only occasional exceptions. In reality, changes in the fuel source or operating conditions prevent the design process conditions from being fully attained. Further, a catalyst performance guarantee “payoff” cannot be interpreted the same as a guarantee for a consumer good – the “make right” conditions are such that the owner invariably incurs additional cost. In some instances the guarantees are contested, depending on how the owner operates the unit and the guarantee language is constructed. Consequently, catalyst guarantees are useful to inform but do not dictate the catalyst replacement schedule. In summary, given the variability in catalyst deactivation rates, and the unpredictable role of factors such as ash plugging, it is not possible to confidently select a “default” catalyst replacement frequency. Replacement periods ranging from less than one year to 3 years have been observed, regardless of a suppliers guarantee.

**Response:** The EPA appreciates the up-to-date input on the catalyst life for SCR. The EPA agrees that the typical catalyst replacement scenario includes adding a catalyst layer to the spare layer followed by replacing a catalyst layer. The EPA also agrees that the catalyst life may be affected by the fuel, reactor design, and application of the SCR, including effects from constituents in the flue gas and presence of As, K, Na, Cl, and others as cited in section 2.2.1 subsection Catalyst Deactivation, along with the P issue cited by the commenter as common for PRB fired units (that operate with staged combustion).

In the response to the previous comment, the EPA noted that additional ranges for typical catalyst lifetime have been included in the final revised SCR chapter for oil- and gas-fired units. While the commenter states that EPA does not recognize that other operating factors affect the reactor potential or catalyst life, the original SCR chapter included a wide range of catalyst life in section 2.2.1 Reduction Chemistry, subsection Catalyst (“For coal-fired boiler applications, SCR catalyst vendors typically guarantee the catalyst for an operating life ranging from 8,000 to 24,000 hours [1]. Applications using oil and natural gas have a longer operating life, typically greater than 32,000 hours [41].”) In the original SCR chapter, section 2.4.2 subsection Catalyst Replacement, there was also discussion of a 2 to 3 year catalyst life for coal-fired units (“For the most common SCR design, the high-dust SCR, a catalyst layer is typically guaranteed for 16,000–24,000 operating hours based on information from catalyst vendors.”) In section 2.2.2, subsection Catalyst Management Plan, EPA includes additional text on catalyst lifetimes in the original SCR chapter (“Currently, vendor-guaranteed life for a catalyst layer in coal-fired applications is typically three years [51], and actual catalyst layer lifetimes in such applications are often in the 5 to 7 year range, depending on the condition of untreated flue gas [33]. Gas- and oil-fired applications experience even longer catalyst layer lifetimes.”) The EPA acknowledges that, in the past, typical catalyst lifetimes for coal-fired units have included additions and replacement every 2 to 3 years. [Jeffers, 2011 for McIlvaine] [Jeffers, 2012 for WPCA] EPA continues to support 3 years as the best estimate for catalyst life but also acknowledges that 2 to 3 years may be justified in certain circumstances.

The EPA appreciates the commenter’s point that vendor guarantees do not always secure a “make right” condition without incurrence of additional costs to the facility. The catalyst guarantees, however, are used as a guideline in the study level costs estimated by the Control Cost Manual. Input from the catalyst vendor on the catalyst lifetime is invaluable. In the Example Problems in the chapter, an assumption of 24,000 hours for the catalyst lifetime is used.

### ***Catalyst Replacement Cost Proposed Method 1 and Method 2***

**Commenter:** Utility Air Regulatory Group and Edison Electric Institute (EEI)

**DCN:** EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024

**Comment:** Catalyst Replacement: Method 1 vs. Method 2

Table 5-1 summarizes the calculated annual catalyst charge using EPA’s proposed Method 1<sup>64</sup> versus the correlation derived in the IPM Cost Model, referenced as Method 2.<sup>65</sup> Table 5-1 presents results comparing each method for a reference 520 MW unit firing eastern bituminous

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<sup>64</sup> Revised Chapter 1, Equations 2.63 and 2.64.

<sup>65</sup> Ibid, Equation 2.67.



coal, and including for EPA Method 1 a sensitivity study addressing the catalyst replacement frequency and changeout cost. Table 5-1 also includes a cost element neglected by EPA in the discussion of catalyst replacement and in the example case – the labor and equipment cost to replace catalyst delivered to the site.

**Table 5-1. Comparison of Catalyst Replacement Cost Methods: EPA Method 1 (Equations 2.63-2.64) and Method 2 (IPM Basis)**

	<b>Method 1 (Equations 2.63 – 2.64)</b>			<b>Method 2 (IPM Model)</b>	
Catalyst Exchange Schedule (Yrs)	3	3	2	Inherent to cost correlation	
Removal/ Installation cost	Not Included	\$1,500/m <sup>3</sup>	\$1,500/m <sup>3</sup>	Not Included	\$1,500/m <sup>3</sup>
Annual Cost (\$/y)	504,000	641,000	1,471,000	1,460,000	1,859,000

*Note: Catalyst unit price for all scenarios \$5,500 per m<sup>3</sup>.<sup>66</sup>*

EPA’s discussion of Method 1 and the example presented contain two unrealistic assumptions – that one layer of catalyst is replaced every three years and that installation cost is negligible.

As noted in the previous section, even if a 24,000-hour catalyst lifetime is obtained, the owner must exchange catalyst at a planned outage that precedes the expiration of the guarantee period. Otherwise, the owner would operate beyond the guarantee period or be forced to implement a special-purpose outage to replace catalyst – scenarios not realistic or prudent. (Although operation beyond a catalyst guarantee period is not unheard of, it can only be assumed based on supporting evidence from laboratory tests of catalyst samples.) EPA’s execution of Method 1 in the draft cost manual adopts this imprudence by “rounding” the “Yfactor” on page 2-76 to an integer value of three (3), thereby assuming either that greater than 24,000 hours is feasible or that a special-purpose outage will be taken to change catalyst. The former is not always correct. The latter action is unrealistic.

There are three factors EPA has not properly accounted for in assessing catalyst replacement costs. First, the catalyst replacement rate is highly variable, and defining the replacement rate based on a catalyst lifetime guarantee presumes a level of success not always achieved or practical, considering major outage schedules and the capacity factor of the unit. Further, basing the catalyst replacement rate on the catalyst lifetime guarantee leaves no margin to account for ash deposition or unavoidable changes in process conditions (e.g., fuel supply).

<sup>66</sup> A competitive procurement for catalyst of different geometry (and in most cases different specific surface area) will yield different unit prices (e.g., \$/m<sup>3</sup> basis).

Second, Method 1 ignores the indirect cost for labor and rental equipment that is required to install the new catalyst. Several workdays of a multi-person crew are required – from three days to up to a week, depending on the infrastructure that exists to support catalyst exchange.

The cost of this action – directly attributable to catalyst replacement and not captured in the fixed O&M charge – can be 30-60% of present catalyst market prices. Discussions with three owners of numerous SCR-equipped units have shared catalyst installation costs. Large units of 800-1300 MW capacity can incur installation costs of approximately \$1,500 /m<sup>3</sup>; for smaller units of 250 MW the cost escalates to more than \$3,000/m<sup>3</sup>.

Third, the volume of catalyst to be replaced must be realistic. As noted in Table 4-1, EPA's projection of catalyst volume is based on pre-1998 experience and can under-predict the volume of catalyst required. Table 5-1 presents the operating cost using present-day estimating practices, includes a state-of-art plate-type catalyst, and assumes an installation charge of \$1,500 per m<sup>3</sup> in addition to new catalyst cost. Consequently, EPA Method 1 – the procedure proposed in the draft chapter for the Air Pollution Control Cost Manual – can be used to predict annual catalyst replacement cost, but it is essential the inputs utilize a realistic catalyst volume, include charges for exchanging catalyst, and are based on a realistic catalyst replacement frequency.

**Response:** As noted in the response to the previous comment, the Example Problems in the chapter use an assumption of 24,000 hours for the catalyst lifetime and 1 catalyst layer is replaced every 3 years. While this is a typical scenario, it may also be that the catalyst replacement frequency is longer or shorter for a particular facility. Both the original SCR chapter and the final revised SCR chapter include ranges for catalyst lifetime that reflect that the catalyst replacement rate is variable, i.e., shorter or longer than the Example Problem. While the commenter notes that the catalyst must be replaced prior to reaching the guarantee period, this is a site specific technical decision for the facility. There are also instances of longer catalyst life with the implementation of good catalyst management plans. Use of the methodology in the Control Cost Manual would require a facility to apply the variables appropriate for the facility situation. Finally, we note that we provided both Methods 1 and 2 for estimation of SCR catalyst replacement cost for coal-fired EGUs in our draft chapter. We believe both are appropriate for estimation of such costs as long as accurate input data are used in their application.

The catalyst volume calculation is discussed elsewhere in this RTC document.

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** Regarding Method 2, the IPM source document does not describe a basis for this method. Examining the cost correlation does not explicitly reveal a catalyst change-out frequency.

**Response:** The associated costs are empirically derived by S&L to represent the “average” for the coal-fired units; it does not specifically list a catalyst life (or change-out frequency) since the owner, based on their operating characteristics, determines the operating life purchased. The location of the SCR and the unit's operating conditions (like: high dust / low dust applications, fuels combusted (bituminous, subbituminous, PRB, lignite, oil, gas), hot side / cold side ESP –

all affect a catalyst's life and the catalyst cost. However, the catalyst change-out frequency listed above, represent the typical catalyst life specified by owners.

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** The empirical formula (method 2) in the EPA manual seems to calculate a much higher cost than the method based on actual replacement (method 1). The causes for this mismatch should be investigated.

**Response:** After review of this and other comments, the Agency recommends either method 1 or method 2 for SCR catalyst replacement cost estimation at coal-fired units. For oil- and gas-fired units, only method 1 is recommended. Oil- and gas-fired units have combustion outlet streams that are very clean compared to those from coal-fired units; in particular, the ash content in such streams from coal-fired units is not a concern from oil and gas-fired unit streams. Oil and gas-fired units also have longer catalyst lives because of their cleaner combustion outlet streams. The Agency notes that the S&L tools are derived for coal-fired units. A coal factor is found in method 2 that makes it inapplicable to oil and gas-fired units. Therefore, only method 1 is recommended for oil and gas-fired units. Based on this and other similar comments, we revised the catalyst replacement cost discussion in Section 2.4.2 to clarify that methods 1 or 2 may be used to estimate catalyst replacement costs for coal-fired boilers and that method 1 should be used for oil- and natural gas-fired boilers. We also added a new equation for coal-fired industrial boilers that was developed by replacing the term  $B_{MW}$  in equation 2.67a by  $Q_B/NPHR$ , as shown in equation 2.67b in the revised chapter.

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** On pages 2-66 through 2-69, the draft Chapter 2 describes two approaches to estimating annualized catalyst replacement costs. Conceptually, we believe either methodology could work for the sources to which they are applicable, but since the second methodology is specific for large coal-fired utility boilers, API believes its applicability to oil- and gas-fired industrial boilers is questionable. As discussed more generally in Comment III.1.2, extrapolation of information from large utility coal-fired boilers to small industrial oil- and gas-fired boilers is highly questionable.

**Response:** The EPA appreciates the input on the use of either cost methodology for estimating catalyst replacement cost.

After review of this and other comments, the Agency recommends either method 1 or method 2 for SCR catalyst replacement cost estimation at coal-fired units. For oil and gas-fired units, only method 1 is recommended. Oil and gas-fired units have combustion outlet streams that are very clean compared to those from coal-fired units; in particular, the ash content in such streams from coal-fired units is not a concern from oil and gas-fired unit streams. Oil and gas-fired units also have longer catalyst lives because of their cleaner combustion outlet streams. The S&L tools are derived for coal-fired units. A coal factor is found in method 2 that makes it inapplicable to oil and gas-fired units. Therefore, only method 1 is recommended for oil and gas-fired units. Based on this and other similar comments, we revised the catalyst replacement cost discussion in

Section 2.4.2 to clarify that methods 1 or 2 may be used to estimate catalyst replacement costs for coal-fired boilers and that method 1 should be used for oil- and natural gas-fired boilers. We also added a new equation for coal-fired industrial boilers that was developed by replacing the term  $B_{MW}$  in equation 2.67a by  $Q_B/NPHR$ , as shown in equation 2.67b in the revised chapter.

**Commenter: San Joaquin Valley Air Pollution Control District**  
**DCN: EPA-HQ-OAR-2015-0341-0027-A2**

**Comment:** The following sentence should be added to the catalyst replacement discussion on page 2-66, based on information in the link [https://online.platts.com/pps/p=m&s=1029337384756.1478827&e=1140211156928.3353357507452834748/?artnum=F2X00RF6VV0213A155358n\\_1](https://online.platts.com/pps/p=m&s=1029337384756.1478827&e=1140211156928.3353357507452834748/?artnum=F2X00RF6VV0213A155358n_1): “The catalyst replacement cost includes the investment cost of a new catalyst, the disposal cost of a spent catalyst, and the environmental costs/liabilities associated with land filling the spent catalyst.”

**Response:** The EPA agrees and has included a statement in the Catalyst Replacement subsection that disposal costs are considered when replacing a layer with new catalyst. The following text has been added to the final revised SCR chapter:

“The catalyst cost,  $CC_{replace}$ , should reflect the current costs for the catalyst, including the costs associated with installing the new catalyst and removing and disposing of the old catalyst.”

### *Detailed Cost Estimates*

**Commenter: Sierra Club and National Parks Conservation Association**  
**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** Applicants for permits typically submit opaque cost estimates that are not supported by unbiased sources. Permitting authorities and the reviewing public generally do not have the knowledge, tools, or access to vendor data to critically evaluate these estimates. This has led to many highly cost-effective controls, widely used outside of the United States and thus clearly cost effective, to be summarily eliminated through either falsehoods in costing or failure to follow standard costing methods. Applicants who do not want to install SCR, for example, will artificially increase costs by including the following items in a lump sum quote without breaking them out:

- Adding unrequired equipment/modifications, such as new stacks, SCR bypasses, boiler stiffening, air preheater modifications, new ID fans when the existing fans are adequate, and/or balanced draft conversions;
- Reporting excessive annual operating costs by including the cost of lost generation during installation (when a normally scheduled outage for installation is adequate) and using unrealistic and unsupported unit costs for power and ammonia;
- Alleging space constraints that require high retrofit factors;
- Including invalid costs such as AFUDC and owners cost; and
- Overestimating annual costs by using unrealistic interest rates and short equipment lifetimes, among many other tricks of the trade.

These calculation problems are often hidden from view by using lump sum estimates. Thus, the revised SCR chapter should discuss each of these issues and explain when it is valid to include these costs and when it is not.

To avoid these hiding-the-ball problems, the budgetary quotes should break out the cost for each piece of equipment, including reactor housing, catalyst, duct work, expansion joints, dampers, sonic horns, ammonia injection system, etc. plus costs for any required facility modifications, such as electrical system upgrades, fan modifications, instrumentation and control systems, and boiler stiffening and justify the need to require each item with plot plans, layouts, engineering calculations, separate vendor quotes for individual items, etc. Further, the revised SCR chapter should explicitly require that all applicant cost analyses be supported by vendor budgetary quotes, including the request for proposal and the resulting cost proposal, signed by a licensed professional engineer.

**Response:** The EPA agrees that cost estimates for SCR need to have sufficient detail for reviewers to understand the key assumptions and data that are included in the capital costs and the annual costs. The EPA also agrees and recommends that vendor quotes should be considered and used in preparing cost estimates for control equipment, including for SCR. We note in the final revised chapter that certain costs are not to be included, e.g., AFUDC and owner's cost, in order to be consistent with the Cost Manual's methodology for cost estimation, and provide the recommended interest rate and equipment life. Several costs are site-specific such as space constraints around the boiler or unit and the need for bypass or ID fans.

**Commenter: Sierra Club and National Parks Conservation Association**  
**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** Regardless of the specific model or method used to estimate cost, certain inputs will always be required to estimate the cost effectiveness of SCR. These include the costs of catalyst, ammonia, and busbar electricity. The SCR chapter should explain how and where to get these inputs.

These costs can vary widely, depending upon geographic location and type of catalyst; therefore, the revised CCM should include a table that reports typical ranges as of the date of publication of the revised chapter. The revised CCM also should lay out a procedure to obtain updated cost estimates for these inputs. This procedure should recommend that vendors be contacted to get FOB delivered prices for the SCR and ammonia reagent. The CCM also should provide a list of vendors for ammonia reagent and catalyst. Most vendors accommodate such requests.

The revised SCR chapter discusses the use of regenerated catalyst. According to the revised proposal, regenerated catalyst costs 40% less than new catalyst and it also eliminates significant disposal costs.<sup>67</sup> However, the proposal did not incorporate methods to calculate these savings. The revised CCM should explain how and when to account for the use of regenerated catalyst. Likewise, the costing methods for reagent should account for the option of using urea to ammonia on demand systems, which can lessen reagent costs in some cases.

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<sup>67</sup> Proposal at p. 2-12.

The CCM should also explain how an analyst can obtain the cost of auxiliary power, based on wholesale prices (where the power would be purchased) or additional generation from the plant at its busbar cost (where auxiliary power would be self-supplied).

Current and historical wholesale prices are widely available for the regional transmission organizations, often to the level of individual plants. For most of the large utilities not in RTOs, historical wholesale prices are available from the FERC Form 714 filings. Forward prices are available for most zones of the RTOs and for most major trading hubs outside the RTOs, from the NYMEX forward markets and other platforms (e.g., the Intercontinental Exchange or ICE, Platts). For rate-regulated generators that report their costs in the FERC Form 1, the busbar cost can be estimated from the cost of fuel reported for the power plant on page 402 or 403, line 43 (or for a plant that burns multiple fuels, by dividing the fuel cost on line 20 by the net generation on line 12. For other plants, busbar cost can be computed from their cost of fuel and heat rate. Whenever the generator is operating, the auxiliary load can be satisfied by reducing the energy delivered to the transmission grid (costing the operator the lost sale at the wholesale price) or by increasing the plant's output.

Retail power prices are rarely relevant to the cost of auxiliary power; if some retail power is required (e.g., for operation of the emission controls during startup and shutdown, when the boiler is operating but the generator is not producing power), the price should be taken from the tariff rate or contract applicable to the specific facility. The large power plants that would install SCR or SNCR usually pay lower-than-average rates. The 6.7¢/kWh used in the cost examples in the proposed SCR chapter appears to be the 2012 national average retail power price for industrial customers, mistakenly labeled as "busbar" cost.<sup>68</sup> This average is almost certainly too high for the prices paid by generators, in addition to being over two years out of date by the release of the draft CCM, which may confuse CCM users.

The draft CCM may have chosen the 2012 prices in the mistaken belief that the power prices do not change over time, so that the auxiliary power costs of a 2018 installation in 2012\$ will be the auxiliary power cost in 2012. That assumption is incorrect for any source of auxiliary power. The CCM should require the use of the most recent actual (or normalized) prices, market forward prices, or independent forecasts should be used for whatever may be the relevant auxiliary power, and that those prices then be deflated to the year's dollars used in the cost effectiveness analysis.

**Response:** The Agency has not provided a list of vendors for reagents or pollution control equipment, but will provide some information on such vendors as part of its work in updating the Control Cost Manual chapters, including the SCR chapter. We agree with the commenter that the electricity price of 6.7¢/kWh used in the examples is more typical of the price for industrial customers and that the rate for electricity generators would lower. However, the use of industrial customer electricity rates makes sense in that these are the rates that users of control technology will face in operating pollution controls. However, we will clarify this in the chapter and update it to mention busbar power rates should be used to estimate electricity costs by electricity generators. For 2012, the average electricity cost was 3.72 cents/kWh for electricity generators based on data collected by the U.S. Energy Information Administration (EIA). We have revised example problem 1 to reflect the lower average electricity cost of 3.72 cents/kWh.

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<sup>68</sup> Proposal at, p. 2-71, and footnote 26.

The electricity cost rates, and other cost rates, shown in the example problems are intended to be only examples. The costs used in the examples are not anticipated to reflect costs in later years; it is expected that current costs would always be used. Users of the Control Cost Manual should use the current electricity price for the cost year (or the latest available rate) in which a cost estimate is made, and not rely on the example 2012\$ electricity rate shown in the example. We expect that current prices be used for all other cost rates as well (e.g., catalyst cost rate, reagent cost rate). We have added the following footnote to the example problems to instruct users to use the rates for the cost year of their estimate:

“The electricity, catalyst, and reagent unit costs used in this example are based on data for 2012. These values are provided here for demonstration purposes only. When estimating direct annual operating costs, the current price of these commodities reflecting the year in which the cost estimate is made should be used. Catalyst and reagent prices can be obtained from vendors. Industrial plants should use the electricity price from their latest utility bill, while electricity generators should use the busbar rate.”

We agree with the commenter that purchase prices for regenerated catalyst are typically 40% less than for new catalyst. However, the use of new catalyst versus regenerated catalyst is a technical decision made by the individual company or facility and not dictated by EPA. For the purposes of estimating annual operating costs, the catalyst price should reflect the current actual cost of the catalyst used in the SCR. If the facility intends to use only regenerated catalyst, then the catalyst price ( $CC_{replace}$ ) used in equation 2.63 should reflect the current purchase price for regenerated catalyst. If the facility intends to use only new catalyst, then catalyst price used in equation 2.63 should be the current price of new catalyst. If the facility intends to use both regenerated catalyst and new catalyst, then the weighted average of the current prices for new and regenerated catalyst should be used in equation 2.63. For clarification, we have added the following text to section 2.4.2 describing how to account for regenerated catalyst use:

“The catalyst cost,  $CC_{replace}$ , should reflect the current costs for the catalyst, including the costs associated with installing the new catalyst and removing and disposing of the old catalyst. Most facilities return used catalyst to the catalyst vendor for regeneration, rather than regenerating the catalyst onsite. Hence, the cost of regeneration is typically incorporated into the cost of the replacement catalyst. Where a plant intends to use only regenerated catalyst, the catalyst cost used in equation 2.63 should reflect the current cost of regenerated catalyst, which may be lower than that for new catalyst. For situations where a plant may use regenerated catalyst and periodically purchase new catalyst, then a weighted average of the current costs for new and regenerated catalyst can be used in equation 2.63.”

### ***Cost Effectiveness Values***

**Commenter: Sierra Club and National Parks Conservation Association**  
**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** The proposed SCR chapter lays out a method to calculate “cost effectiveness” in dollars per ton of NO<sub>x</sub> removed per year.<sup>69</sup> A control technology is considered to be “cost

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<sup>69</sup> Proposal at p. 2-70.

effective” if it falls within a reasonable range of cost effectiveness values. Cost effectiveness is determined by comparing the annual cost per ton of pollutant removed for the source to the range of cost effectiveness values for other similar sources. If a given cost effectiveness value falls within the range of costs borne by others, it is *per se* cost effective unless unusual circumstances exist at the source.<sup>70</sup> Thus, cost effectiveness is a relative determination, based on costs borne by other similar facilities.

Unfortunately, the proposed SCR chapter failed to include any cost effectiveness values for the types of facilities that typically install SCR. Rather, it includes only tables that summarize cost data in other units, such as dollars per kilowatt, dollars per million BTUs fired, or dollars per short ton of clinker.<sup>71</sup> These metrics cannot be accurately converted into dollars per ton.

The revised SCR chapter should include a discussion of the cost effectiveness determination and a table that summarizes SCR cost effectiveness values that have been found to be cost effective for facilities that commonly use SCR, (e.g., gas-fired turbines, coal-fired power plants, refinery heaters and boilers), in units of dollars per ton per year.

Further, in making the cost effectiveness determination, costs are compared to ranges reported for other “similar sources.” Applicants will commonly attempt to eliminate SCR by narrowly defining the range of what is considered to be a “similar source” by, say, limiting the determination to only those units firing a specific type of coal, such as “North Dakota lignite” or “Texas lignite” or Powder River Basin coal. The EPA should clarify what constitutes a “similar source” for purposes of making a cost effectiveness determination, based on procedures in the CCM. We recommend that “similar source” be broadly defined as “similar source category”<sup>72</sup> to include all units of a given type, (e.g., all coal-fired boilers, all gas turbines, all utility sources, all cement plants, all refineries, etc.).

**Response:** The Table 2.1a and 2.1b information was meant to provide example capital cost values for SCRs applied to various sources. These examples are intended to provide information on typical estimates of costs for SCR applied to individual units. The Control Cost Manual is meant to provide guidance for estimating costs. In the Control Cost Manual, the Agency has not typically provided cost-effectiveness values for applying control measures broadly across source categories or provided similar source definitions or determinations. It is not our intention to provide such information in this version of the Control Cost Manual, though the procedures and data in the Control Cost Manual for estimating costs could serve as input to estimating cost-effectiveness values if desired.

### ***Equipment Life of SCR***

**Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)**

**DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024**

**Comment:** UARG believes that the use of a 30-year estimate of equipment life for SCR is arbitrary and unreasonable. The sources cited in the draft SCR chapter are based on experience

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<sup>70</sup> 70 Fed. Reg. 39,168 (July 6, 2005).

<sup>71</sup> Proposal at Table 2.1a.

<sup>72</sup> NSR Manual, p. B.5.



in other industries or on speculation and do not support a conclusion that future SCR retrofits will have a 30-year lifespan.

The lifetime of an SCR process is determined by numerous factors, including the useful life of the balance-of-plant equipment and of generating components (e.g., the boiler and the steam turbine). EPA's proposal that 30 years should be considered a useful lifetime is arbitrary and references cited by the EPA are not substantiated. Specifically:

- Reference 22 cites refinery experience that is not relevant to coal-fired power generation since refinery process equipment is physically smaller than comparable reactors for coal-fired boilers, and thus not subjected to the same thermal stresses induced in larger units due to expansion and contraction. Also, refinery SCR processes do not necessarily cycle with load in the same manner as power generation equipment, presenting less induced thermal stress. In addition, the refinery gas treated is low in particulate matter; thus construction materials do not experience the same erosion and degradation.
- Reference 90 cites a North Carolina report in a contentious litigation that stated the author's opinion that a 30 year life is feasible, but provided no data supporting that position.
- Reference 91 cites a Quantitative Risk Analysis of Options report for managing and storing anhydrous ammonia reagent, specifically determining the annualized risk of managing the reagent "...upstream of the SCR reactors". The 30-year life stated in this report pertains to the reagent preparation and delivery equipment and not to the process reactor.
- Reference 92 cites a report on the San Juan Station prepared for a Federal Implementation Plan cites engineering studies that have assumed greater than a 20-year lifetime; however, the 30-year lifetime is an assertion and not documented experience that can be broadly applied.

Applying a 30-year lifetime assumes that the EGU on which the SCR is installed will remain economically competitive over that time span, an assumption that may not be valid for many potential SCR retrofit candidates under current regulatory and economic trends. For decades, electric generating companies and the Control Cost Manual have used a 20-year lifetime for evaluating the economics of control equipment and other similarly large investments. The usual assumption of a 20-year lifetime is appropriate now, based on the uncertainty in generating plant remaining useful life and the variability of fuel prices.

**Response:** As we noted in the draft Cost Manual chapter, data collected from multiple independent sources indicated that an equipment life of 30 years for SCR installed on utility boilers and 20 to 30 years for SCRs installed on industrial units was an appropriate and realistic estimate. We also noted in the chapter that in certain situations the remaining useful life may also be a determining factor in determining the appropriate SCR equipment life. The estimate of equipment life, as defined in the Cost Manual, is for design and operational life. This would differ from the 20 year estimate endorsed by the commenter since there are different bases for these estimates.

**Commenter: American Petroleum Institute (API)**

**DCN: EPA-HQ-OAR-2015-0341-0020-A1**

**Comment:** On page 2-69 of the draft Chapter 2, it is reported that for the purpose of estimating indirect annual costs an SCR lifetime of 30 years has been assumed. The draft provides various citations, primarily indicating a 20-30 year lifetime. Our members indicate SCR units on refinery or petrochemical equipment are typically designed for a 20 year life.

**Response:** For the response to this comment, please see the response to the previous comment.

**Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.**

**DCN: EPA-HQ-OAR-2015-0341-0022-A1**

**Comment:** Based on our members' experience, the expected lifetime of an SCR is 20 years (with regular catalyst replacement).

**Response:** For the response to this comment, please see the response to the first comment in this section.

**Commenter: Xcel Energy**

**DCN: EPA-HQ-OAR-2015-0341-0029-A2**

**Comment:** Unique site conditions play a part in determining the actual estimated equipment life for each SCR installation. Some of the factors entering into this consideration are: expected remaining life of the boiler, turbine and generator; the existing unit; and scope of other work being done on the generating unit to keep it functional for the remaining life of the facility. Therefore, the use of a fixed equipment life for all SCR projects of 30 years is not representative of actual useful life for a given project. The Manual should allow each project to justify and utilize a site-specific estimate of equipment life for the SCR.

**Response:** For the response to this comment, please see the response to the first comment in this section.

**Commenter: Arizona Public Service Company (APS)**

**DCN: EPA-HQ-OAR-2015-0341-0028-A1**

**Comment:** A reasonable estimate of SCR equipment life is 20 years. EPA's use of 30 years is based on broad assumptions regarding stagnant economic and technology considerations. Environmental equipment is often upgraded or replaced with new technology before it has reached the end of its useful life. For internal cost assessments, APS uses 20 years or less. The accounting depreciation life for this equipment is 20 years.

**Response:** For the response to this comment, please see the response to the first comment in this section.

**Commenter: Sierra Club and National Parks Conservation Association**

**DCN: EPA-HQ-OAR-2015-0341-0025**

**Comment:** We generally agree with EPA's estimates for SCR lifetime, but note the range provided is for SCRs installed in a "hot-side" location. SCRs in other locations would have a longer lifetime. A tail-end SCR, for example, has a lifetime well in excess of 30 years due to low temperatures and absence of corrosive agents at the tail end of the plant, following other pollution control equipment. The SCR chapter should be modified to explain that the lifetime depends on the location of the SCR in the flue gas stream since temperature and contaminants in the flue gas affect lifetime. The lifetime of an SCR is the lifetime of the metal frame, which is at least as long as the lifetime of the facility in which it is installed, which might easily be over 80 years. Support equipment, such as the ammonia injection system, may have a shorter lifetime, but a separate capital recovery factor should be applied to this equipment, which contributes a tiny fraction of the total SCR cost.

The lifetime ranges reported in the SCR chapter are at the lower end of the plausible range. A boiler, or a refinery, for example, has a useful life of well over 80 years. If an SCR is installed in a new facility, its lifetime will be much longer than the 20 to 30 years cited in the SCR chapter. Many SCRs that were installed on facilities in Europe and Japan in the 1980s are still in operation today.

We agree that the lifetime of a retrofit SCR is limited to the remaining useful life of the facility. However, it is important to clarify in the revised SCR chapter that if the remaining life of the facility is used to set the SCR lifetime, and it is less than the lifetime of the SCR, an enforceable facility shutdown date must be required in the operating permit.

**Response:** We agree with the commenter that tail-end SCRs may have longer equipment lives than 30 years due to the lower levels of dust and corrosive compounds in the exhaust gas. The information we have reflects high-dust applications, for which 30 years is an appropriate estimate. We currently have insufficient information to specify an equipment life for tail-end SCRs. However, we expanded the section 2.2.3 to discuss in more detailed the advantages of tail-end SCRs, including longer catalyst and SCR equipment life achievable with the tail-end configuration.

## **2.5 Example Problem 1**

No comments received.

## **2.6 Example Problem 2**

No comments received.

## 2.7 Other Comments

### *Formatting, Numbering, and Typographical Errors*

**Commenter:** Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

**DCN:** EPA-HQ-OAR-2015-0341-0022-A1

**Comment:** There are two sections labeled as 2.4.1.3.

**Response:** The EPA thanks the commenter for their input. The error in the subsection titles has been fixed in the final section.

**Commenter:** American Petroleum Institute (API)

**DCN:** EPA-HQ-OAR-2015-0341-0020-A1

**Comment:** In the table of contents for Chapter 2, the title for Section 2.4 should be indented only as much as other section headings and not as much as a subsection heading.

**Response:** The EPA thanks the commenter for their input. The formatting error in the table of contents has been fixed in the final revised SCR chapter.

**Commenter:** San Joaquin Valley Air Pollution Control District and American Petroleum Institute

**DCN:** EPA-HQ-OAR-2015-0341-0027-A2 and EPA-HQ-OAR-2015-0341-0020-A1

**Comment:** There is a typographical error on page 2-68 in the second paragraph for second catalyst replacement cost methodology. EPA should replace “&L cost methodology” with “S&L cost methodology.”

**Response:** The EPA thanks the commenter for their input. The formatting error has been fixed in the final revised SCR chapter.

**Commenter:** American Petroleum Institute (API)

**DCN:** EPA-HQ-OAR-2015-0341-0020-A1

**Comment:** *Chapter 2, Pages 2-67 through 69*

These pages explain the two approaches EPA presents for estimating annual catalyst replacement costs. However, in the first approach English units (i.e., cubic feet) are used and in the second approach metric units (i.e., cubic meters). This difference carries over into the examples. This is confusing and API recommends, consistent with the other calculations in the draft, that English units be used everywhere.

**Response:** The EPA agrees and has updated to English units in the final revised SCR chapter.

